UTM/RMC/F/0026(1998)

UNIVERSITI TEKNOLOGI MALAYSIA

BORANG PENGESAHAN
LAPORAN AKHIR PENYELIDIKAN

TAJUK PROJEK : COGENERATION POTENTIAL IN INDUSTRY

Saya PROF. DR. K. S. KANNAN
(HURUF BESAR)

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FINAL PROJECT REPORT

COGENERATION POTENTIAL IN SELECTED MALAYSIAN INDUSTRIES (VOT : 72013)

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ABSTRACT

The increase in energy cost in recent years has created a situation where it has become essential to develop alternative energy technologies. Energy efficiency does not only mean reducing environmental degradation and increasing sustainability but also cost savings. Most energy managers employ common solutions to reduce plant inefficiencies in Malaysia such as "Energy Auditing", equipment replacement etc. One other energy efficient system is Cogeneration. Cogeneration can be considered as one of the many indications of progress in a healthy and efficient industrial growth. Cogeneration enables an industry to be not totally dependent on the utility supply but become inter-dependent and hence increasing availability. A well-planned cogeneration system can create a situation where plant operation need not be affected by utility blackouts; i.e. minimum production capacity is maintained. The Malaysian energy environment is a dynamic growth, where present excess capacity is projected to be fully utilised by the end of the century. The increasing demand for electricity is not evenly distributed in Malaysia and this off balance cause overloading in some areas. By cogenerating, the demand can be reduced and therefore the load on Tenaga Nasional Berhad or TNB transmission lines will also reduce. This would allow TNB to react to load fluctuation more effectively. Cogeneration will be a catalyst for the local natural gas industry since most industrial cogenerators (between 1MW to 10 MW) will be utilising natural gas as fuel source for gas engines and gas turbines. Cogeneration will also displace the need to build expensive power plants, which will mean eliminating transmission and distribution losses. Cogeneration will benefit the environment by reducing emissions, improve the use of natural resources, introduce better grid management, provide savings in Ringgit Malaysia, increase efficiency, added reliability and generating growth in the gas industry. The objective of this project was to evaluate the technical and economics viability of cogenerating in Malaysia. Two case studies were selected and evaluated. It was found that the lack of firm regulations and gas prices are the main factors discouraging cogeneration in Malaysia. Local industries were also found to be lacking in commitment towards cogenerating and efficient energy use. This thesis has forwarded recommendations and suggestions that will be required to improve the cogeneration scenario in Malaysia.

ABSTRAK

Peningkatan kos tenaga berguna telah meningkatkan keperluan untuk menjimatkan penggunaan tenaga dengan berbagai teknologi baru. Kecekapan penggunaan tenaga akan membawa kesan positif kepada pemeliharaan alam sekitar serta penjimatan kos. Salah satu cara menambahkan kecekapan penggunaan tenaga ialah dengan menggunakan Audit Tenaga di mana alatan atau proses pembuatan dapat dikenalpasti penggunaan jumlah tenaga dan diperbaiki dari segi kecekapan. Satu lagi cara yang efektif ialah dengan menggunakan sistem penjanaan Elektrik dan Haba atau Sistem Penjanaan Bersama. Sistem ini kini digunakan dengan meluas di Eropah dan Amerika Syarikat. Sistem ini akan membolehkan sesuatu industri berfungsi tanpa bergantung sepenuhnya kepada syarikat bekalan elektrik. Sistem yang dirancang dengan teliti akan membolehkan industri tersebut meneruskan operasi walaupun terdapat masalah pada talian elektrik negara. Permintaan tenaga elektrik di Malaysia adalah satu perkembangan dinamik di mana jumlah penjanaan terkini dijangka digunakan penuh pada akhir abad ini. Permintaan elektrik di Malaysia pada masa kini adalah tidak seimbang yang menyebabkan permintaan yang melebihi had di beberapa kawasan. Pembangunan yang pesat akan membawa kepada situasi di mana pernintaan bekalan eletrik negara dalam talian negara akan berkurangan dan ini akan membolehkan Tenaga Nasional Berhad (TNB) berfungsi dengan lebih cekap. Sistem ini juga akan membawa kemajuan kepada industri gas asli di negara kita kerana ia adalah sesuai untuk sistem penjanaan kecil (1MW - 1OMW). Sistem penjanaan elektrik dan haba bersama juga akan mengurangkan keperluan untuk membina stesen kuasa elektrik yang besar. Adalah pasti bahawa penggunaan sistem ini akan membawa kebaikan kepada semua pihak. Pengurangan penggunaan tenaga akan memberi kesan positif kepada alam sekitar, bahan semulajadi negara, pengurusan talian elektrik negara yang lebih baik, prestasi pengeluaran dan perkembangan industri pembekalan gas. Objektif tesis ini adalah untuk mengkaji potensi sistem penjanaan bersama dalam industri Malaysia. Kajian yang dilakukan mendapati bahawa kekurangan dari segi peraturan yang jelas dan harga gas asli yang tidak tentu adalah faktor utama yang menjadi penghalang utama implementasi sistem ini. Kajian ini juga mendapati bahawa industri tempatan tidak mengutamakan penggunaan tenaga secara optimum dan juga tidak memberi perhatian serius terhadap penggunaan sistem penjanaan elektrik dan haba. Tesis ini telah memberi beberapa cadangan untuk mengatasi masalah-masalah yang dihadapi oleh sistem ini di Malaysia.

CONTENT

CHAPTER I

EVALUATION OF COGENERATION PLANT

1.1 Introduction

As mentioned earlier in the previous chapter any engineering project will require an evaluation based on technical aspects and economic viability. This chapter will describe the method and purpose of evaluating a cogeneration plant.

1.2 Walkthrough

The walkthrough is a quick method of assessing a cogeneration plant where further analysis would be based on the results of this preliminary study. Figure 6.1 describes the walkthrough analysis in a flowchart format, which is self-explanatory.

1.2.1 Site Visit

The site visit is conducted to determine the plant's present operating conditions and expected expansion scenario. The visit should provide details on energy consumption, layout, special requirements etc.

1.2.2 Initial Preliminary Investigation

This is the initial visual and basic assessment of the site conditions. The important factors in this step is to identify the plant location with respect to gas pipeline connection, location within the plant, accessibility of units to be installed, current plant layout, i.e. boilers, air heaters etc.

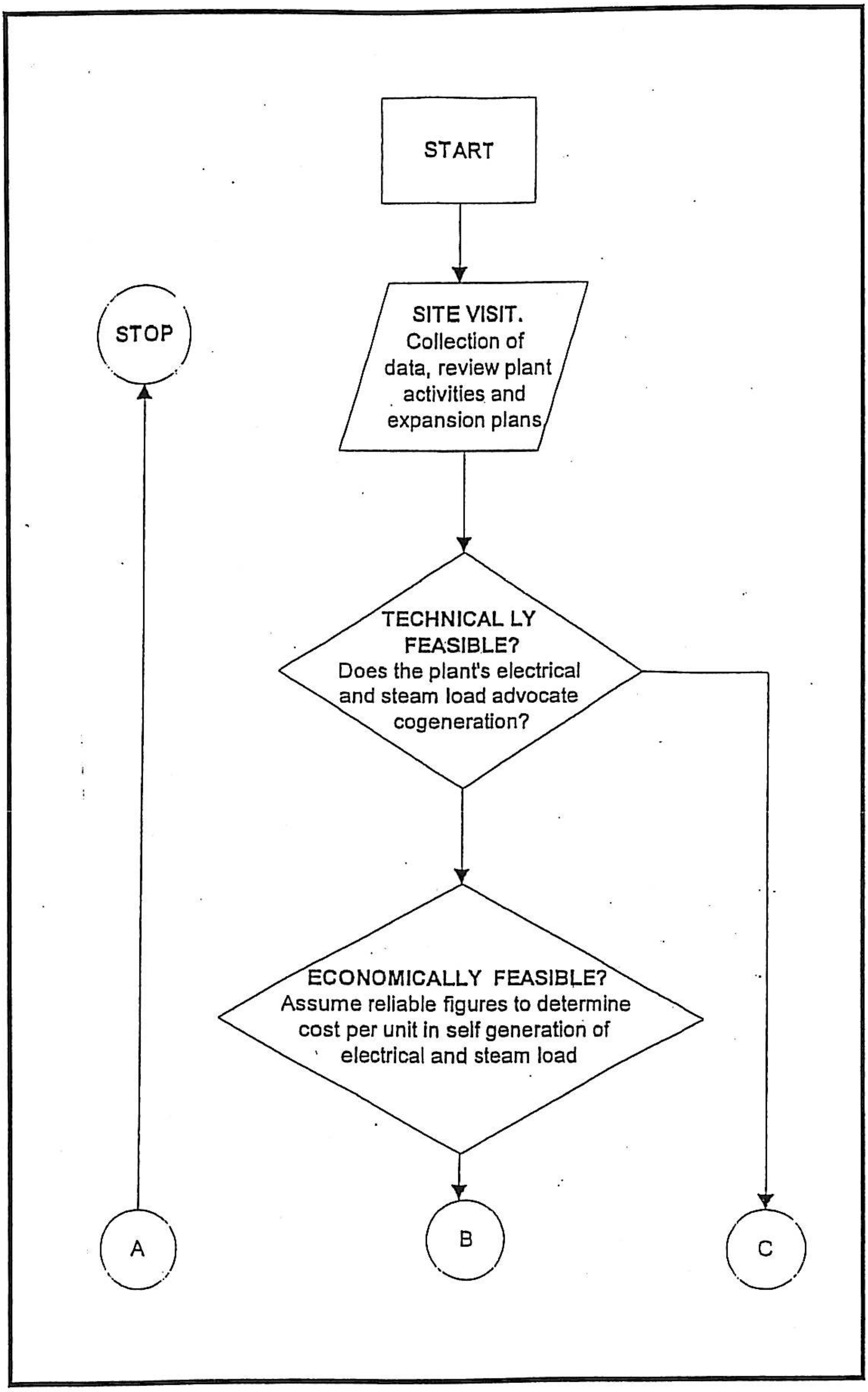

Figure 1-1 Walkthrough Analysis Flowchart

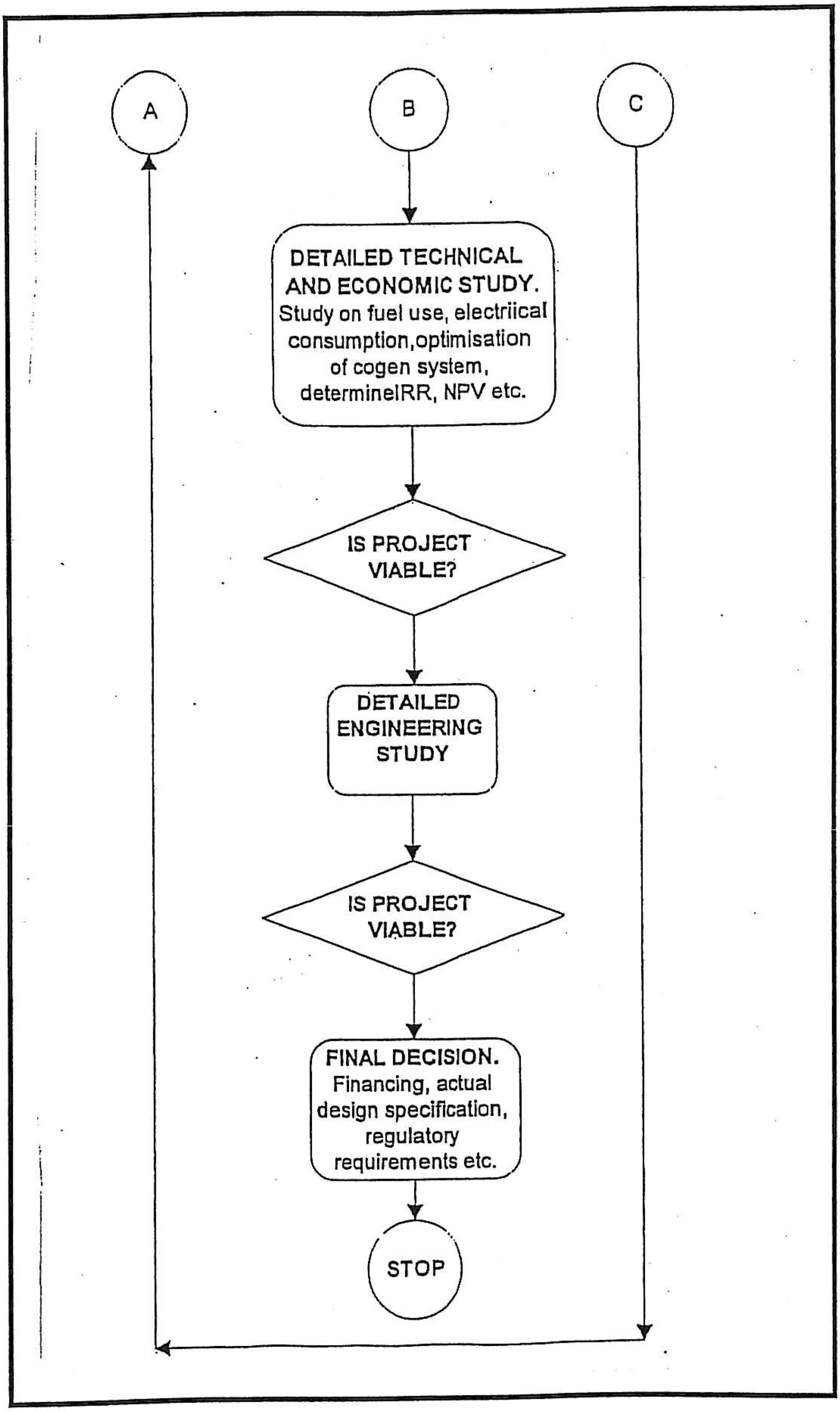

Figure 1-1 **Walkthrough Analysis Flowchart (continued)**

Natural gas pipeline systems and availability is crucial in implementing natural gas fired cogeneration systems. If natural gas is not readily available, the project need not be considered at all. Cogeneration plant layout within the overall plant layout is important. Land scarcity and cost may override the economic considerations of the plant, where for example the current plant might be able to incorporate newer technologies to boost production capacity while maintaining or even lowering energy consumption cost. Current plant systems such as boilers may need replacing if it is aged but there are possibilities of newly installed boilers may prove more cost effective not to be replaced by a cogeneration system.

In all, the investigator should consider future expansion, i.e. land requirements, new natural gas pipelines before he or she can decide to proceed with the assessment.

1.2.3 Energy Load Profile Investigation

If the initial investigation described in the preceding section proves to be satisfactory, energy load profiles have to be obtained. As described earlier, cogeneration systems produce heat and electrical energy simultaneously; hence only current heat energy and electrical load demand need to be measured. All measurements made must be as accurate as possible to truly assess the energy needs of the plant which requires the investigator to obtain on site data collection while complementing it with plant data records, historical and present.

Future energy loads due to plant expansion or modifications should be taken into consideration. The investigator may assume the size of the expansion but it should be within reasonable limits and according to the industry expectations in the future.

As described earlier, cogeneration systems produce heat and electrical energy simultaneously; hence the energy consumption profile is then measured and evaluated. The type of data that is required to evaluate a cogeneration plant is described below: -

i) Electrical Measurements

Electrical data can be obtained from utility electrical bills that would indicate the peak, of peak usage in kWh and the maximum demand charge. Tenaga Nasional Berhad (TNB) billing system includes other information such as reactive power and real power values to calculate the power factor of the plant, type of tariff, additional charges if there is any and any other specific information if there is a need. Utilities such as TNB do not used seasonal charges since Malaysia is situated in the tropics, hence fuel prices is not greatly affected by winter conditions. The walkthrough analysis in this section would provide the investigator the type of data available and its reliability. Utility historic energy bills are the most reliable data when compared to plant data obtained from readings from meters and submeters. Comparing historic bills and plant meter readings would enable a more accurate scenario of energy usage of the plant.

TNB does not implement a time of day demand, i.e. maximum demand is not affected by peak or off peak charges, hence for hourly electrical consumption plant, we have to rely upon readings from meters and submeters. It would be appropriate to analyse utility billing for the past year or two, which would provide the energy usage trend in the plant. Plant meter readings can be taken for duration of one or two months to obtain the energy usage on a daily basis. To improve the data analysis the maximum demand by hourly basis can be taken from plant meters. This particular maximum demand data would not be necessary if the plant experiences constant power demand due to process reasons or proper energy management policies. The electrical data would provide the investigator the plant requirements during peak and off peak hours and maximum demand requirements, which will indicate the plant's energy usage trend. As mentioned earlier consideration has to be taken for plant expansion since it would affect the overall plant design.

ii) Steam Consumption

The steam consumption of the plant is obtained by taking readings from plant meters or plant data records. Steam consumption is usually given in kilograms per hour (kg/hr) or pounds per hour (Ib/hr) The steam consumption analysis should correspond to the electrical data duration. Steam consumption may be analysed by considering consumption during electrical peak and off -peak periods and obtaining the highest and the lowest consumption for 24 hours. The data should be spread over duration of a few months to obtain an average that would describe the plant steam energy consumption trend. It is necessary to obtain the average steam flow required by the plant. There may be some cases where the required steam flow cannot be supplied totally by the cogeneration plant, which would require supplementary firing of the HRSG. Steam quality required for the plant must be determined based on the temperature, pressure and water to vapour ratio. This is necessary for the waste heat boiler design or HRSG, which will be based on this values and the required steam flow.

iii) Fuel Data

Heat energy for most industrial plants is in the form of steam and or hot air. Steam is generated by boilers and hot air by air heaters. Both devices require fuel input to produce these forms of energy. By analysing the fuel use data by the plant, the plant energy consumption for heat energy can be calculated. The duration of readings should be corresponding to the duration of electrical data taken for the analysis. The quantity of steam or hot air produced by the proposed cogeneration system can be translated into displaced fuel, which is the quantity of fuel required to produce the same amount of heat energy by conventional means. The fuel type used must be identified to provide the lower calorific value, composition and combustion efficiency. Once the type of fuel used by the conventional boilers and air heaters are known, the energy consumption in kilojoules (kJ) or British thermal units (Btu) can be calculated.

1.2.4 Technical Feasibility

The immediate action after the initial site visit is to decide whether there is a need for a cogeneration plant technically since existing equipment and systems may be operating with acceptable efficiency levels and including a cogeneration system would need modifications to the existing plant. There is also possibility of this been overridden by the need for a constant, reliable supply of minimum power for the plant to operate if the utility supply is not efficient.

On the completion of the site visit, project viability can be analysed. Cogeneration plants, with gas turbines as prime movers produce approximately 2 times more heat energy than electrical energy, i.e. heat to electrical energy ratio equals 2. This ratio would determine if the cogeneration plant were to be designed as a matched or un-matched system. In most cases the plant would be an un-matched one where top-up power may be required from the utility company or an additional conventional boiler will need to be installed.

It is common practice to install a cogeneration plant with the capacity to provide the electrical baseload with additional top-up from the grid. The amount of steam generated by this system would then be utilised completely by the plant process. If the steam requirement is less than that produced by the cogeneration system, then downsizing the prime mover would be required but it should be kept in mind that smaller capacity gas turbines cost more hence the price of electricity generated would increase. For a quick evaluation of prime mover type and heat recovery factors, the list in Table 1.1 can be utilised for assessing a the fuel consumption and heat recovery based on the kilowatts hours produced by the cogeneration plant. Once the appropriate prime mover size is known an economic evaluation can be conducted.

Table 1-1 Engine Fuel and Heat Recovery Factors Characteristics

PRIME MOVER	FUEL (MMBtu/kWH	HEAT RECOVERY FACTOR (MMBtu/kWH)
Reciprocating Engine		
<100 kW	0.0130	0.0060
100kW to 500kW	0.0125	0.0055
>500kW	0.0110	0.0050
Gas Turbine		
< 1000kW	0.0167	0.0095
1000 to 5000kW	0.0133	0.0070
5000kW to 15,000kW	0.0111	0.0050
>15,000kW	0.01	0.0045

1.2.5 Economic Viability

The primary reason for installing a cogeneration plant is to generate savings and reduce energy cost. In this section, the system is evaluated based on an average utility cost and assumptions, which may not be the actual economic performance of the plant. It is best to use less optimistic assumptions to produce a lower economic performance since a detailed economic analysis would yield better results.

The economics performance is easily obtained by conducting the economic walkthrough exercise. The assumptions made are on engine operating hours, operation and maintenance cost, gas prices (since Gas Malaysia has yet to produce tariffs rates and at current is negotiable) and installed cost. The economic screening takes into consideration all electrical cost, fuel cost, electrical savings and fuel savings to obtain a simple payback period. If the simple payback should produce a satisfactory value then a more detailed technical and economic screening is warranted.

1.2.6 Detailed Technical Study

This process is in actual fact an extension of the previous steps. This section will take into consideration the technical details such as layout details, plant modifications, natural gas delivery pressure and supply, standby fuel such light kerosene, scheduled and unscheduled shutdowns, standby power etc. Table 6.2 shows the expected operating hours without shutdowns for a month. The data can then be incorporated to with scheduled and unscheduled shutdowns to obtain the true operating hours.

Table 1-2 Typical Engine Operational Hours

Prime Mover Type	*Hours of Operation per month*	*Reliability (evaluated Over 30 day month)*
Reciprocating Engine	648	90%
Gas Turbine	705	98%

Additional considerations is needed to determine whether the cogeneration system would be able to function effectively where for example if there are frequent natural gas supply cuts, then maintenance and operating cost would see an increase and hence forth.

1.2.7 Economic Screening and Concepts

The economic analysis or screening is done to ensure that the project pays for itself in a limited number of years and to generate savings over its lifetime. Cogeneration plants save energy consumption it does not create profits. This difference must be kept in mind if at all times during the implementation of the project.

Several economic factors must be taken into consideration such as:

i) Value of the cogenerated power and heat relative to the cost of conventional power and heat.
ii) The cost of fuel , both the cogeneration plant fuel and the conventional system fuel.
iii) Maintenance cost of the cogeneration plant.

The factors above is essentially the most primary economic factors due to the fact that the cost of generating power should not be more than the purchased cost form the utility.

Malaysian industrial sectors are charged by the Time of Day rate where the hours are divided into peak and off-peak. This aspect is important since a baseloaded cogeneration plant may be less costly when compared to peak period charges but at the same time it may cost higher than off peak charges. Taking the average cost of purchasing power can dismiss the argument on the cost of purchasing power. The end analysis would depend on the investigator of the cogeneration scheme.

To analyse the cost of cogenerating power, the turbine's working hours would need to be assumed. For example, assuming a reliability of 90 %, the turbine load factor for a 30-day month is 684 hours. Peak hours in Malaysia are 14 hours, which allows the investigator to calculate to peak and off peak power production. By taking into consideration the top-up power from the utility grid, the total power cost can be obtained. The cogeneration power cost must take into consideration all cost i.e. capital and variable cost as shown in the following chapters. The table below provides a basic rule of thumb cost for prime mover types.

Table 1-3 Variable and Fixed Cost of Prime Movers

PRIME MOVER TYPE	OPERATION & MAINTENANCE (RM/kWh)	FIXED COST IN MILLIONS (RM /kW)
Reciprocating Engine	0.038	1.7
Gas Turbine	0.0125	2.5

1.2.8 Financial Decisions

This part is the most critical of all cogeneration schemes due to the high investment capital cost. The investigator may need to determine the source of financing, risk analysis, IRR and other economic factors. For this thesis, the economics used to evaluate the cogeneration plant can be obtained from most economic and financial investment textbooks and would not be elaborated.

1.3 Conclusion

Once the walkthrough is proven to be successful, the investigator should look into other matters such regulations and restrictions. Licence is issued by the Department of Electricity and Gas (J.B.E.G), which also acts as the regulatory body. Interconnection details should be discussed with relevant authorities, i.e. the utility company since any fault in the cogenerator part may affect the surrounding area. Since regulations and interconnection details have not been finalised, they are not discussed here.

CHAPTER II

CASE STUDIES

2.1 Introduction

Case studies were selected to provide a more realistic design and implementation of the research work. There were no specific criteria on the selection for the case studies except that both had shown interest in cogeneration and both utilised electrical and steam energy. Since data from both case studies were obtained for 1996; the data collected was assumed to be identical for 1997 and using expected increments on energy usage and cost, a 20 year cash flow analysis was conducted. This was done to adhere to near realistic figures rather than assuming an increase in 1997.

Only Case Study One is discussed in this chapter although both are of equal importance. A brief result of the findings for Case Study Two is found at the end of this chapter.

2.2 Description of Case Study

Case Study One and Two are different types of industrial plants. Case Study One is a chemical processing plant and Case Study Two is a food processing plant where both plants have multiple products. A brief description of the activities of Case Study Two is in Appendix D. Both case studies were evaluated using the walkthrough method established the economics is based on methodology. Cogeneration can be applied when the electrical cost is the prime energy cost. It is typical that electrical energy is the highest contributor to operating cost in a typical industrial plant.

Case Study One can be considered as a typical case where electrical energy consumption exceeds steam energy consumption. In Case Study One electrical energy can be considered as prime energy in terms of process and cost while steam energy as secondary energy. It should be understood that both are required for the process but the operating cost incurred due to electrical energy consumption is much higher than the steam energy cost.

Case Study Two is also another typical case where it is a high steam energy consumer and an average electrical energy consumer. This case study requires a variable steam load but a near constant electrical energy need. Case Study Two prime energy need is the steam load but the disparity of energy cost between electricity and steam still places electrical energy as the prime energy cost. This clearly demonstrates that electrical energy is usually the highest contributor in operating cost of an industrial plant.

2.3 Evaluation - Case Study One

Case study 1 is an industrial chemical plant which produces hydrogen and chlorine gases as its main products (see Figure 2.1). The process is a basic electrolysis process where electrical current is passed through a solution of brine (NaOH). Due to the ionisation of the brine, hydrogen and chlorine are obtained in the cathode and anode of the electrolysis system respectively. Hydrogen and chlorine are collected in their gaseous state and transported to holding tanks for distribution. Sodium is chemically reacted with hydrogen to produce sodium hydroxide. Sodium hydroxide or caustic is mixed with chlorine vapour to produce sodium hipachlorite. Sulphuric acid and hydrochloric acid is also produced in the plant.

Due to the use of electrolysis in the process, the electrical energy consumption is high. The plant also utilises a hydrogen dryer where wet hydrogen enters a heat exchanger and exits at $-72^{0}C$ dew point. The heat exchanger medium is compressed air, which passes through the desiccant gel. The gel is heated up by a electrical heater when it is saturated with water. The plant requires heat energy in the form of steam for caustic evaporation and brine treatment during start-ups. Other than that, facilities heat energy requirement is minimal.

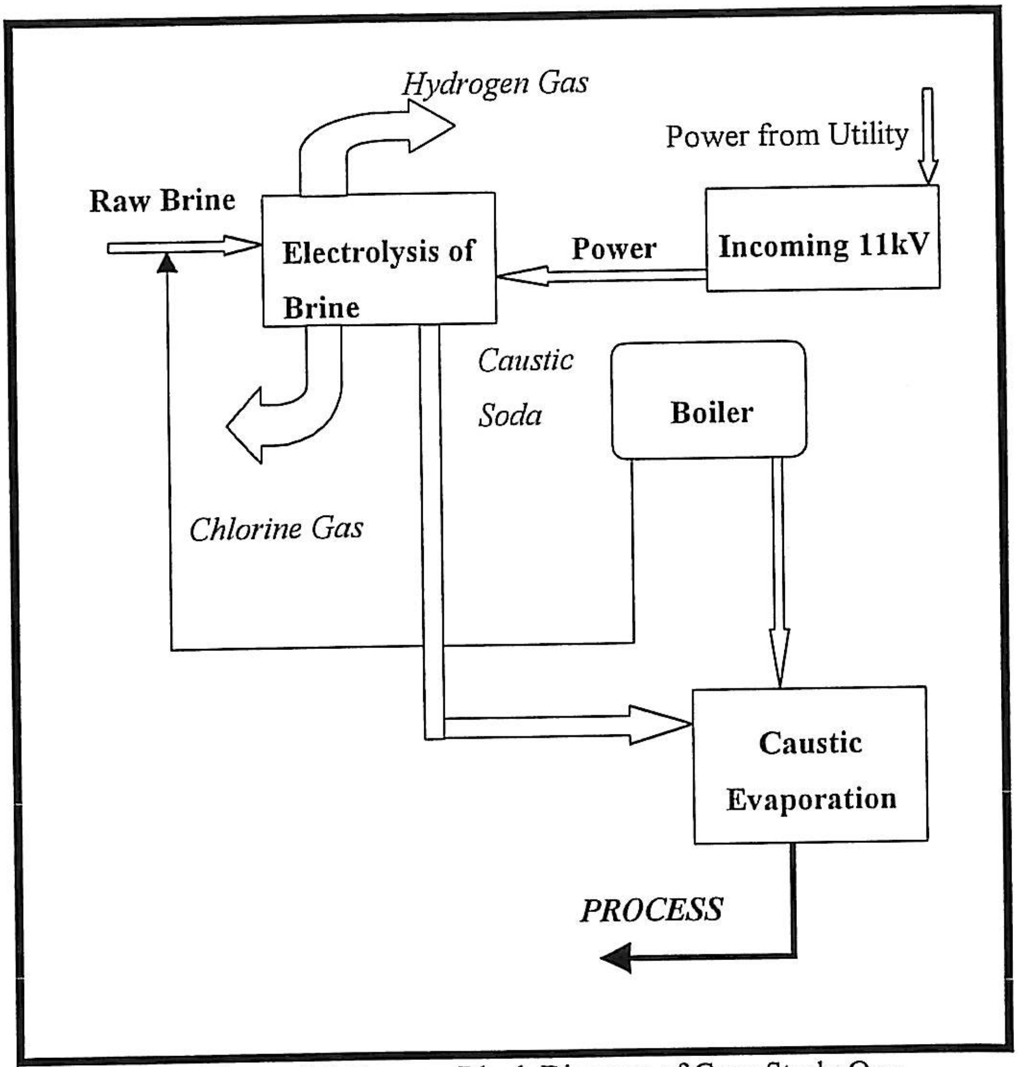

Figure 2-1 Process Block Diagram of Case Study One

The site visit(s) were conducted to obtain electrical and steam data and to focus on the needs of the plant in terms of energy demand. The plant's main use of heat energy is in the form of steam. The table below summarises the plants operational conditions:

2.3.1 Data Collection

2.3.1.1 Electrical Data

Electrical data on site was logged but can be considered unreliable due human error, metering error etc., hence previous year's bills were analysed. The steam load was fixed at 4 tons per hour. Table 2-2 shows the electrical consumption based on utility bills. This is the most reliable data available and most cogeneration experts prefer to use previous utility bills to evaluate a site's electrical requirement. This is due to the fact that most industrial plants do not maintain a perfect set of records and hence the data may not represent the actual usage. The historic utility bills can be considered as the most reliable set of data and therefore provide a non argumentative representation of the electrical consumption. Table 2-3 is a summary of the plants electrical consumption for the year 1996.

Table 2-1 Present Plant (Case Study One)Operating Parameters - Steam and Electrical

BOILER	
Boiler Fuel	1500 Sec Redwood No 1. (Medium Fuel Oil at 100 ^{0}F)
No of Boiler	1 (plant in concern only- expansion not considered)
Operation	24 hours (hr), 7 days a week
Pressure	150 psig (10.34 bar)
Temp	185 ^{0}C
Steam Flow (Design)	7937kg/hr (17,500Ib/hr)
Steam Flow (Operating	4000 kg /hr
Return Steam	90 ^{0}C
Plant Shutdown	15 days a year or 8400 operational hours
Design Pressure	157 psig (1.087 bar)
Boiler Fuel Cost	0.36 sen per litre as of April 1996
Electricity	
Profile (Consumption)	24 hours / 7 days a week
Maximum Power	9.1 MW
Minimum Power	9.1 MW
Generator	500kW
Plant Voltage	22kV (incoming)
	137kV (85%) - DC Power
	415 (15%) - AC Power for Auxiliary Equipment

Table 2-2 Electrical load profile of Case Study One

Month	Days	*Peak*	Off-Peak	Total kWh	Maximum Demand	Load factor (Hours)	Cost (RM)			Addition Charges	Discount	Total Payment
							On Peak	Off Peak	Max Demand			
Jan '96	31	3265640	2289260	5554900	8976	618.86141	522502.4	183141	152592	16664.7	0	874899.9
Feb	28	3589730	2565080	6154810	9104	676.05558	574356.8	205206	154768	18464.4	0	952795.63
Mar	31	3312300	2353940	5666240	9104	622.39016	596545.2	235629	183436.5	5609.58	-96056.6	925164.136
Apr	30	3528940	2621080	6150020	9008	682.72869	670498.6	288319	195473.6	0	-152727	1001564.2
May	31	3535660	2513540	6049200	9072	666.79894	671775.4	276489	196862.4	0	-150922	994205.6
June	30	2480280	1857140	4337420	9200	471.4587	471253.2	204285	199640.0	0	-117108	758070.2
July	31	3458967	2496187	5955154	9061	657.22922	588024.39	224657	166722.4	0	0	979403.62
Aug	31	3458967	2496187	5955154	9061	657.22922	588024.39	224657	166722.4	0	0	979403.62
Sept	30	3458967	2496187	5955154	9061	657.22922	588024.39	224657	166722.4	0	0	979403.62
Oct	31	2171160	1537340	3708500	5984	619.73596	369097.2	138361	110105.6	0	0	617563.4
Nov	30	3144460	2280200	5424660	8352	649.50431	534558.2	205218	153676.8	0	0	893453
Dec	31	3460920	2426840	5887760	9824	599.3241	588356.4	218416	180761.6	17663.3	0	1005196.88
											0	
total		38865991	27932981	66798972	105807	7578.5455	6763016.6	2629035	2027484	58402		10961124

Table 2-3 Summary of Power Consumption Characteristics of Case Study One.

Average Baseload	7952.25 kW
Highest Max Demand	9824 kW
Lowest Max Demand	5984 kW
Average Max Demand	8817.25
Average Peak Consumption	7931.83 kW/h
Average Off Peak Consumption	7759 kW/h
Average Consumption	7845 kWh
Average Load Factor	0.631

The average load factor for this tariff class is 0.67. The cost of purchasing power from TNB (including maximum demand) can be calculated in RM/kWh. This is shown in Table 2-4.

Table 2-4 Cost of Purchasing Electricity from TNB

Average Cost of Energy Purchase from TNB (RM/kWh)*	0.14
Average Cost of Purchase of Maximum Demand (RM/kW)	0.052
Average Cost of Purchase of Maximum Demand (RM/kWh)	0.03
Total Cost of Purchase from TNB for 1996	0.17

Table 2-5 is the electrical billings from January to April 1997. This is included to observe the changes in electrical usage for the same corresponding months in 1996. This is to detect the current trend in electrical consumption of the plant.

* The term energy purchase and power purchase is meant to define the cost or electrical power based on kWh consumption.

Table 2-5 Electrical Usage for 1997 -January to March

Month	On peak, kWh	Off Peak, kWh	Max Demand, kW	ΔPeak ('96-'97)	Δoff Peak	Δ Max Demand
January	3556160	2501580	9632	290520 (8.8%)	212320 (9.2%)	656 (7.3%)
February	4450960	3219720	12096	861230 (24%)	654640 (25.5%)	2992 (32.8%)
March	3140860	2278120	9600	-171440 (-5%)	-75820 (-3%)	496 (5%)

It is difficult to assess the exact trend 1997 is heading towards in electrical energy consumption. Except for the month of February, the increases have been within acceptable limits. Hence due to insufficient readings, 1996 has to be compared with 1992-1995 readings which is not included due to request from the case study in concern. It was observed that from 1993 to 1994 and 1996 have similar energy consumption trends while 1995 had a slightly higher consumption. Due to the observations made it can be safely concluded that the 1996 data is sufficient for the analysis.

2.3.1.2 Steam Data

Steam data from the plant records were minimal. The fuel consumed is the most probable way to observe the steam production and hence verify the steam flow data. A single day reading from the boiler plant room is given below.

Table 2-6 Fuel Consumption for Boiler

time	Flow (litre)	Flow l/2hr)	Flow(l/hr)	Cumulative
0600	4161900			
0800	4163250	1350	675	
1000	4164450	1200	600	1275
1200	4165650	1200	600	1875
1400	4167060	1410	705	
1600	4168370	1310	655	3235
1800	4169710	1340	670	3905
2000	4171030	1320	660	
2200	4172410	1380	690	5255
2400	4173100	690	345	5600
0200	4174810	1710	855	6455
0400	4176200	1390	695	7150

The average fuel use is calculated to be 650 litres per hour. To verify this data, several calculations were made to assess the existing boiler plant. The calculations showed that the boiler consumes approximately 357.5 litres of fuel per hour. The variation could be due to the return fuel flow is not accounted for.

2.3.2 Site Considerations/Initial Decision on Size of Cogeneration System

It was decided that the electric heater and desiccant dryer will not be displaced since the overall plant operations would need to be redesigned, hence causing extended shutdowns which translates to losses. Furthermore, all plant operations should not be dependent totally on the cogeneration system to function. By separating the dependency, i.e. diversifying the energy source, the plant would still be able to operate at least with minimum operational conditions. The expected expansion of the plant was taken into consideration, where steam demand is expected to increase to 10 tons per hour in the next five years which provides a higher heat to electrical ratio. (at current the heat to electrical ratio of the plant is averaged at 1.3). Another important characteristic of the future plant design is that two or more isolated systems would exist. Therefore the current plant can be taken as a sub-plant or the "plant" † as it would be called from here onwards, requires 4 tons per hour of steam. Plant 1 requires 60 % of total power to continue its operation, which means any time the plant would need 60 % of the average consumption of 7800 kW/h which means a minimum of 4680 kW of power is required. The cogeneration system might provide an opportunity to operate at least one sub-plant during total power failure in the grid.

The current boiler room was identified as the most suitable location for the cogeneration system since existing pipelines may need only minor adjustments and hence reduce downtime and cost. The pipelines to the newer plants (expansion plans) are also simple and non-obtrusive.

The size of the plant cannot be designed by using optimisation methods simply because, regulatory requirements from Jabatan Bekalan Elektrik dan Gas or JBEG has stated that all plants must be baseloaded to the steam requirements, especially when the heat to electrical ratio is low. Hence, if the plant was to be optimised using economics as the criteria for optimisation, the plant designed might become thermodynamically inefficient due to heat wastage. (Electricity is a higher priced energy compared to steam, hence economic optimisation would place priority to electricity). Based on this restriction, it can be seen that, the plant size would be based on steam requirements. As mentioned earlier, the expected increase of production would proportionally increase the steam consumption to approximately 10 tons per hour. This requires a prime mover, which is capable of supplying that quantity of steam at 1034.22 kPA. A simple rule of thumb is that actual site rated (taking into consideration altitude, ambient temperature etc.) gas turbine would

† The cogeneration system is designed to provide electrical output for Plant 1 only but it is will supply the total steam requirement of Plant 1 and the other sub-plants. The term plant is used for the Plant 1.

produce approximately 2 to 2.5 times the quantity of steam at 150 psig saturated without supplementary firing. A quick calculation shows that a gas turbine rated at 4 MW at site should be able to produce approximately 10 tons of steam which is the required amount for the plant. This is after taking into account expansion plans for similar modular plants within the existing plant. Since gas turbines are affected by site conditions, an appropriate turbine must be selected in the detailed technical study will allow the turbine power output to be down rated according to site conditions.

2.3.3 Technical Viability

At present the heat to electrical ratio of the plant is approximately 1.3. The plant is a high electrical consumer with very low steam usage. Cogeneration is most suitable for plants with a heat to electrical ratio of 2, which is also the ratio of production for steam and electricity for a gas turbine cogeneration plant. Therefore it may not be useful to cogenerate in this plant as a matched plant, hence the cogeneration plant must be unmatched plant, i.e. top-up power from TNB must be purchased. Gas Malaysia supplies gas to District stations at 413.688 kPA (60psig) which is reduced to 137.896 kPA (20 psig) at the service station. Service stations are located within the plant's boundary and hence, land has to be allocated. Since turbine requires gas at high pressure >137.896 kPA, compressors will need to be fitted in the service station. Maintenance of the service station is to be borne by the customer, however weekly check will be made by Gas Malaysia personnel.

An absorption chiller system can be incorporated into the system to produce the plant's cooling requirement but it will not be advisable to do so due to high capital and maintenance cost. A conventional centrifugal chiller with efficient overall design may prove more cost effective.

The plant's layout and available gas pipelines makes the cogeneration plant to be technically viable so the next step is to assess a quick economic screening.

2.3.4 Economic Feasibility

It was calculated that the cost of purchasing electricity is approximately RM 0.17 per unit of power or kWh including maximum demand charges (see Table 2.4). A quick economic viability assessment can be made by calculating the cost of generating electricity by cogeneration. The combined heat and electrical savings method is used to calculate the cost of generating. The breakdown in cost of generating is given below:

a) Capital Cost

In the formula used to calculate the cost of cogenerating, the factor, α, is the capital charge factor which is also known as the annuity factor and is given by the equation below:

$$\alpha = i(1+i)^N / ((1+i)^N - 1) \tag{2.1}$$

which is related to the discount rate factor, i and the life of the plant. The discount rate can be taken as the interest rate charge for debts. At end of August 1996, the base-lending rate was 9.35% therefore the interest rate taken into consideration in this ana lysis is 10%. α is calculated below using annuity tables that can be obtained from any book on financial management:

$$\alpha = 0.117$$

The cost of a plant is approximately RM 2.2 million per MW for gas turbines and the proposed capacity of the plant ISO rated at 5MW, therefore capital charge factor is :-

$$\alpha(CI)_{CO} = 0.117 \times 2.2 \times 5MW = RM\ 1.287 \text{ million}$$

The capital cost factor is only used to calculate the unit cost of electricity but it is not included into the project cash flow analysis over the lifetime of the project.

This is because time value of the capital should not be considered since the main concern is in the input cost and the subsequent savings.

b) Cost of Cogeneration Fuel -Natural Gas

The cost of natural gas is expected to be RM 10.00 per MMBtu. This value is based on current rates provided by Gas Malaysia to its existing customers. Tariff rates for cogenerators have yet to be issued and the prices are still negotiable. Gas Malaysia has indicated that the gas prices would be approximately 30 % more than medium fuel oil. Fuel consumption of a 5 MW gas turbine is approximately 55.63 MMBtu per hour‡ (see Table 2-7). Hence for a turbine operating 8000 hours per annum (assuming plant experiences shutdown for 400 hours per annum) would require:

Total Fuel Consumption = 445040 MMBtu/annum

the total cost is then :

$$(C_f)_{CO} = 10.00 \times 445040 = \text{RM } 4.4450 \text{ million/annum}$$

c) Standby and Maintenance Cost

Standby charges works out to be RM 350,000 per annum while maintenance is levelled at RM 300,000 per annum.

d) Cost of Fuel for Boiler Plant

The average price of medium fuel oil in 1996 was 36 sen per litre. It was determined by calculations that 357.5 litres is consumed per hour. The total working hours is 8400 since standby boiler enables total hours of operations, hence the total fuel consumed by the boiler is: -

$$8400 \times 357.5 = 3003000 \text{ litres per annum.}$$

‡ This is just a preliminary calculations, hence the fuel consumption is obtained for turbine operating under ISO conditions

Therefore the cost of purchasing MFO, $(C_f)_{CO}$ is :

$$(C_f)_{CO} = 3003000 \times 0.36 = \text{RM } 1081080 \text{ per annum.}$$

e) Total Generating Cost

The total cost per annum in millions for cogenerating is obtained as:

$$C_{CO} = 1.2 + 4.4 + 0.35 + 0.3 = \text{RM } 6.29 \text{ million/annum}$$

The savings due to displacement of medium fuel oil (purchase is deducted from the value calculated in section **(d)** above) is included in a modified equation (The annual maintenance cost and capital cost factor of the boiler plant is not included)

$$C_{CO} = 6.29 - 1.08 = \text{RM } 5.21 \text{ million/annum}$$

The cost per unit energy is obtained by dividing the cost with the total plant installed capacity, which is 4.25 MW at site. The total power generated, W_{CO} is :

$$(W_E)_{CO} = 8000 \times 4250 \text{ kW} = 34000000 \text{ kWh}$$

The savings per kWh is:

$$(\Upsilon_E)_{CO} = \text{cost of cogenerating/ Total power generated} \qquad (2.2)$$

$$= 5210000/\ 34000000 = \mathbf{RM\ 0.15\ /kWh}$$

The cogeneration plant is also displacing a fraction of the total maximum demand, which would otherwise be charge by the utility. This saving is calculated in terms of kWh. The total maximum demand saved is 4MW. Tariff E2 charges RM 18.40 kW/month, hence the savings per annum in terms of kW, $\Upsilon(_{CO})_{MD}$ is:

$$(\Upsilon_{MD})_{CO} = 4000 \times 18.40 \times 12 = \text{RM } 883200\text{/annum}$$

The total generated power is 34000000kWh, hence maximum demand savings, $\Upsilon(co)_{MD}$ in terms of kWh is:

$$\Upsilon(co)_{MD} = 883200/34000000 = \textbf{RM 0.03/kWh}$$

Therefore the total savings in terms of kWh is:

$$= \Upsilon(E)_{CO} - \Upsilon(co)_{MD}$$
$$= \textbf{RM 0.12 kWh}$$

The cost of generating electricity using the "matched" cogeneration plant, i.e. not considering top-up power purchase from the utility; is lower than the purchase price from TNB by **RM 0.05 or a 29.41 %** savings on unit cost of electrical power (see Table 2-4). This gives a optimistic result for the economic screening. The next step is to evaluate the cogeneration system by implementing a more thorough technical and economic analysis. Further analysis including top-up power purchase will provide actual savings of the cogeneration plant but at this point, the concern is only in the cost of generating.

The graph below is a simple analysis of the unit cost for different generation capacity with gas priced at RM 10.00. It is assumed that the fuel consumed is at ISO conditions and maintenance cost is fixed at RM 300, 000 regardless of the turbine size. It can be clearly seen that the lowest generation cost is at approximately 4400 kW to 4500 kW. Higher capacity turbine will not necessarily mean a cheaper generation cost as shown by the chart.

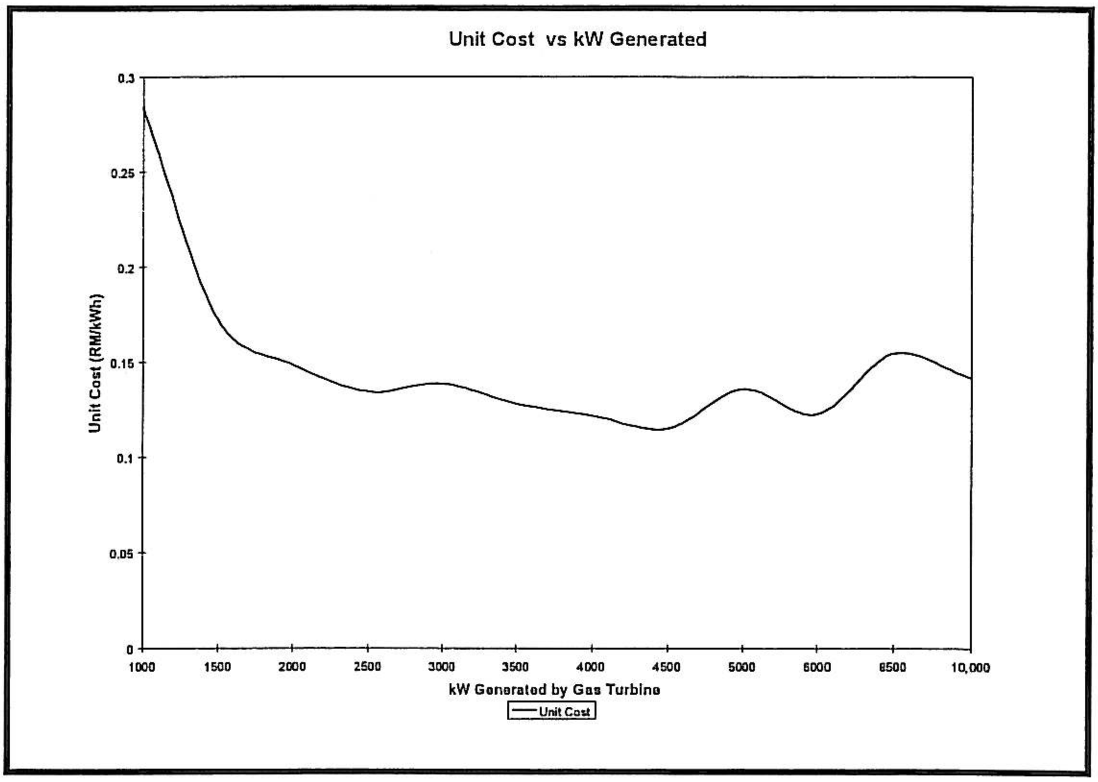

Figure 2-2 Quick Unit Cost Analysis

It should be noted that the graph above is only a quick indication to the independent or "matched" cogeneration plant that would be incurred by different generation capacity and it is not an accurate measurement. The chart can be made more specific by including the purchase power cost from the utility (meaning unmatched cogeneration plant). By including the purchase power cost, the actual savings will be obtained.

2.4 Detailed Technical Study.

It has been established that a cogeneration plant is feasible technically and economically. The next step is to decide the type of turbine, location and other auxiliary units associated with the cogeneration system.

2.4.1. Prime Mover Selection

The most suitable prime mover size is 4 MW on-site, non-ISO rated gas turbine. As mentioned earlier, high reliability and lower maintenance schedule of the gas turbine should be considered when comparing to gas engines. Further more the gas engines heat recovery is concentrated on hot water applications, which is not suitable for the process involved in this plant. The gas turbine, although with a higher capital cost is the chosen prime mover due to its effectiveness in the plants operations.

The natural gas pipeline is within the site area, therefore connection is not a problem. The turbine selected is a Taurus 60 rated ISO 4849 kW and a performance analysis on the turbine was done with two ambient temperatures, i.e. 30 ^{0}C (80^{0}F) and 22 ^{0}C (70.6 ^{0}F) for day and night variations. Humidity level selected is 90 % and standard losses for inlet and outlet pressure drops (4 in. water and 7 in. water at inlet and outlet respectively). Site elevation is assumed at 70ft or approximately 20 metre above sea level. The analysis results for ambient temperature of 30 ^{0}C is given below.

Table 2-7 Specific Site Performance of Taurus 60 Gas Turbine

AMBIENT TEMPERATURE, ^{0}F	86	86	86	86	86	86
Part Load	100%	90%	80%	70%	60%	50%
Power Output, kWe	4128	3715	3302	2890	2477	2064
Fuel Flow, MMBtu/hr	50.88	47.50	44.19	40.86	37.63	34.88
Heat Rate, Btu/kW-hr	12326	12787	113380	14139	15192	16658
Exhaust Flow, Ib/hr	156606	156532	156545	156890	156522	156434
Exhaust Temp., ^{0}F	925	871	821	771	725	680

The minimum power output is 4128 kW and the steam generated by the exhaust is 11,000 kg per hour, hence the turbine meets both the economic and technical criteria.

2.4.2 Site Location

The turbine location should be as such that it minimises the modifications to the plant and hence reduce the shutdown period during installation. The most suitable place would be the existing boiler room area. The area is approximately 18 metres by 13 metres. The Taurus 60 dimensions is given below:

Table 2-8 Approximate Package Dimension and Weight

GENERATOR SET DESIGN PACKAGE	LENGTH M	WIDTH , M	HEIGHT, M	WEIGHT, KG
Taurus 60	8.76	2.44	2.95	27.215

Since the turbine has been designed to be compact, lightweight and vibration free, the site soil conditions need not be investigated since the existing boiler has been in place over the same area for an extended period unless it is deemed necessary.

The waste heat boiler is expected to be 10 metres in length and 4 meters in width. Therefore total area is approximately 19 by 4 metres. The boiler room area is sufficient enough to provide a control room and other minor auxiliaries.

2.4.3 Suitability for Cogeneration

The final aspect of the detailed technical study is the review of the study beginning from initial starting point. Discussion with the plant supervisor and other relevant staff on the advantages and disadvantages in cogenerating will need to be conducted. This discussion is an isolated factor that depends on the plants requirements, layout etc. As mentioned earlier, land scarcity and newer technologies with higher production output but lower energy consumption might be available at the fraction of the cogeneration system.

Forced draft fans will be needed for the HRSG to provide fresh air in case of turbine shutdown. The air will be drawn in and fired by a burner at the inlet of the HRSG. The size of the fan should be such that the flow of air has a turbulent flow similar to the exhaust gases of the turbine. Higher airflow will cause decrease the firing temperature and hence reduce the efficiency of the system. The firing temperature must be designed not to exceed the initial HRSG design for the gas turbine exhaust.

2.5 Performance of the Proposed Cogeneration Plant.

The proposed cogeneration plant was evaluated using the thermodynamic and thermoeconomics factors.

The proposed cogeneration plant was evaluated as an independent cogeneration system, i.e. a "matched" plant where all electrical and heat load was assumed to be met by the cogeneration plant. It was also evaluated as a dependent plant, i.e. where the heat load is met but the electrical load is not, which is the actual scenario. The respective values are compared with Timmermans [5] values in Table 4-1 and a correlation was obtained, which verified the calculations.

Table 2-9 below is the summary of the performance of the cogeneration plant and the reference plant. (It should be noted that some of the performance characteristics such as thermal efficiency (η_{th}) and incremental heat rate (IHR) of the cogeneration plant is equal since the plant in both types of system is isolated).

Table 2-9 Thermodynamic Performance of Proposed Cogeneration Plant for Case Study One

System/ Criteria	**Reference Plant**	**Independent System**	**Dependent System**
ηth, %[§]	30	27.7	27.7
EUF %	36	81.58	30
FSR	N/A	0.34	0.26
$\eta_{A, \%}$[**]	N/A	77.26	77.26
IHR	N/A	1.68	1.68
$\eta_{HRSG/B}$, %[††]	77	84[‡‡]	84
(η_0), %	14	72.6	19
F^T	7.26	3.61	5.40

The thermal efficiency of the reference plant is approximately equal to that of the cogeneration plant but it should be noted that larger turbines are more efficient in producing power. The overall efficiency of the independent cogeneration plant is higher since it does not consider the efficiency of the conventional power plant which is the case for the dependent system. There are situations where the turbine may need to operate at part load and hence the performance suffers. The table below provides the performance of the turbine at various part loads using the data from Table 2-7.

[§] This assumption includes conventional power plant efficiency and distribution losses.
[**] $\eta_{A, \%}$ and IHR is equal for both the independent and dependent system since this criteria only considers the cogeneration plant as a stand-alone (independent plant).
[††] Independent and dependent systems have the same HRSG, hence the similar efficiency.

Table 2-10 Part Load Performance of Proposed Cogeneration Plant

PART LOAD/CRITERIA	90%	80%	70%	60%	50%
ηth, %	26	25	24	22	20
EUF	0.78	0.76	0.76	0.71	0.62
FSR	0.55	0.51	0.44	0.41	0.35
η_A . %	69	66	65	59	55
IHR	1.92	2.08	2.17	2.54	2.96

It can be clearly seen that the cogeneration plant performance deteriorates as the load reduces. The quantity of fuel required generating electricity relative to the heat output (IHR) increases as the part load reduces.

By using table 2-9 and 2-10, the performance of the cogeneration plant can be evaluated.

2.6 Detailed Economic Study

Detailed economic study involves accurate costing for the cogeneration plant, actual standby charges, gas prices etc. The study should also consider payback periods, net present value and internal rate of return. Several assumptions were made to predict the future trends in energy cost and availability. The assumptions are as follows:

a) Electrical energy cost increases at 2 % for the first three years, from 1997 to 1999 and at 1% annually for the subsequent years with an 5% hike every five years.

b) Electrical Consumption increases 1 % annually for from 1997 to 1999.

- this due to the planned expansion of the total plant capacity to 18mW maximum demand.

‡‡ Taken as high efficiency conventional boiler.

c) Medium fuel oil (MFO) prices increases at 1% annually an additional 3% hike at five year intervals.

- This includes transportation cost , higher index indicator and expected scarcity

d) Natural gas increases at 1% annually with an additional 3% hike at five year intervals.

e) The cogeneration system is expected to decrease in electrical output at 0.5% per annum.

- This is to take into account of degradation of components and overall system efficiency

f) The base lending rate for 1996 was average at 9.75% hence the discount rate taken is at 10% for the economic analysis

An important point in this case study is that the electrical consumption over the lifetime of the project would not consider the total plant expansion, i.e. the new sub-plants. This is to reduce the complexity of the analysis and to avoid problems associating the new plant with the existing old plant. The steam requirement for the plant would consider the total plant consumption, which includes the expansion since the cogeneration plant would supply all steam needs but not the total electrical needs. In short, the cogeneration plant is reducing the cost of purchasing electricity in the current plant and would not affect the electrical consumption of the subsequent expansion.

2.6.1 Expected Electrical Savings.

Jabatan Bekalan Gas dan Elektrik or JBEG has approved a new tariff calculation method for cogenerators. (See Appendix B for full details on top-up and standby rates provided by TNB circular 1/97). The calculations assume that the methodology of calculating the billing charges does not change over the 20-year lifetime period of the plant.

The methodology for calculation for the total payment for a month is as follows:

a) Step 1: Determine the calculated Maximum demand, MD_C

The calculated demand can be obtained as:

$$MD_C = (W_{EP}) / (ALF \times Hours)$$

where ALF = Average Load Factor

W_{EP} = the purchased power or top-up from TNB = $(W_{EP})_P + (W_{EP})_{OP}$

Hours = is the total hours in the month.

b) Step 2- Determine Top-Up and Standby Requirements

The plant is to generate 4.1 MW. The Declared Demand for Top-Up, MD_{TU}, is 10 MW based on historical data. Although the maximum demand on February 1997 reached 12.1 MW, it is an isolated case which requires investigation by the plants supervisors. Standby Demand, MD_{SB}, is the required demand if the turbine is shutdown for any reason, hence it is 4.1 MW.

c) Step 3- Determine Calculated Demand Category for Each Month

The calculated demand would need to be compared to the Declared Demand for Top-Up and Declared Demand for Standby, MD_{SB}.

It should be noted that if the maximum demand of the plant is higher than MD_{TU}, the cogenerator would be required to pay a heavier cost but it is also important not to declare a higher standby value since the cogenerator is required to pay for it.

d) Step -4 Calculate Monthly Cost of Purchasing Electricity from TNB

This step is to determine the cost for each month using the categories available. The annual cost is taken after the monthly cost has been determined.

2.7 Project Cash Flow Analysis

The Declared Demand for Standby, MD_{SB} is 4.1 MW. Table 2-11 in page 145 is the cost of purchasing electricity from Tenaga Nasional while cogenerating with a 4.1MW plant. The cost of purchasing power is in column 12 and the Calculated Maximum Demand, MD_C is in column 11. Since the M_{DC} is lower than the MD_{TU} for all the months in 1996, equation B2 to B4 is used for the calculation. The savings gained due to cogeneration are shown in Table 2-12 column 5.

The savings for the months of 1996 are assumed to be equal to the months in 1997. Taking into consideration all the assumptions listed in section 6.5, a cash flow analysis can be made. This cash flow analysis would provide a simple payback, internal rate of return and the net present value of the project.

Table 2-12 takes into account the savings made by displacing a partial amount of purchased electricity from TNB where column 6 is the percentage of the savings made. The cost of purchasing electricity includes standby charges and is obtained from formulas given by Tenaga Nasional Berhad (TNB). Table 2-13 is the final assessment of the economic analysis. The Table includes all cost including a levelised turbine maintenance cost and an equity cash flow analysis, which assumes a bank loan with an interest of 10% is taken for the total capital cost. All the assumptions made in section 2.5 are taken into consideration in this analysis. Figure 2-3 is graphic representation of the project cash flow analysis.

Table 2-11 Purchase Cost of Electricity with Cogeneration

Month	Days	Without Cogen				With Cogen				Calculated	Purchased	Remarks
		Peak	Off-Peak	Maximum Demand	Load factor (Hours)	Peak	Off Peak	Maximum Demand	Load Factor	Max Demand	Cost	(5 day Shutdown)
Jan '97	31	3265640	2289260	8976	0.618861408	1486240	1141260	4876	0.538863823	5446.72	495704.2	
Feb	28	3589730	2565080	9104	0.67605558	1982530	1294080	5004	0.654798161	6792.31	528075.4	
Mar	31	3312300	2353940	9104	0.622390158	1532900	1123940	5004	0.530943245	5507.55	502077.6	
Apr	30	3528940	2621080	9008	0.682728686	1806940	1350080	4908	0.643239609	6544.40	536042.132	
May	31	3535660	2513540	9072	0.666798942	1756260	1283540	4972	0.611383749	6301.41	564600.195	
June	30	2480280	1857140	9200	0.471458696	758280	791140	5100	0.303807843	3211.90	340440.2	Shutdown
July	31	3458967	2496187	9061	0.657229224	1679567	1225187	4961	0.585517839	6021.46	400252.497	
Aug	31	3458967	2496187	9061	0.657229224	1679567	1266187	4961	0.593782302	6106.46	541615.312	
Sept	30	3458967	2496187	9061	0.657229224	1736967	1225187	4961	0.597088087	6140.45	537930.412	
Oct	31	2171160	1537340	5984	0.619735963	391760	512340	1884	0.479883227	1874.17	253039.8	
Nov	30	3144460	2280200	8352	0.64950431	1422460	1009200	4252	0.571886171	5040.75	472976.2	Shutdown
Dec	31	3460920	2426840	9824	0.599324104	1681520	2426840	5724	0.717742837	8516.50	653869.907	
total		38865991	27932981	105807	7.578545519						5826623.86	

Shutdown is for Five Days in the Month

Table 2-12 Cogeneration Electrical Savings

Month	Days	Conventional	Cogeneration	Savings	Savings %
Jan '97	31	874899.9	495704.2	379196	43.34
Feb	28	952795.63	528075.4005	424720	44.58
Mar	31	925164.136	502077.6	423087	45.73
Apr	30	1001564.2	536042.132	465522	46.48
May	31	994205.6	564600.1952	429605	43.21
June	30	758070.2	340440.2	417630	55.09
July	31	979403.62	400252.4972	579151	59.13
Aug	31	979403.62	541615.3125	437788	44.70
Sept	30	979403.62	537930.412	441473	45.08
Oct	31	617563.4	253039.8	364524	59.03
Nov	30	893453	472976.2	420477	47.06
Dec	31	1005196.88	653869.907	351327	34.95
total		10961123.8	5826623.856	5134500	

Table 2-12 above is the savings that would have been made if cogeneration was on line in 1996. The savings are based on the electrical savings only and does not take into account the operational and capital cost of the cogeneration plant. Cogeneration savings should be at least 20% when taking into consideration of all other cost. The total cost and savings generated is shown in Table 2-13 in the next page.

Table 2-13 Cash Flow Analysis for 20-Year Period for Case Study One

1	2	3	4	5	6	7	8	9	10	11	12	13	15	16
Year	*Present Cost*		*With Cogeneration*					*Costing*						
	Electrical Cost without Cogen	MFO (for Boiler inl. Maintenance	Electrical Cost With Cogen (including Standby	Natural Gas (for Gas Turbine)	Cogen Maintenance	Debt Servicing	Debt Flow	Cost (No Cogen)	Cost (Cogen)	Project Cash Flow	Cumulative Cash Flow	Equity Cash Flow	NPV Ratio	NPV
1996	10,854,632	1193830	-	-	-	8,000,000	8,000,000	12,148,461	(12,000,000)	(12,000,000)	-12000000	-4000000	1	-12000000
1997	11,071,724	1507501	5,826,624	3,931,762	300,000	-906,875	7,093,125	12,679,226	10,058,386	2,620,840	-9,379,160	-4,472,285	0.893	2340409.861
1998	11,293,159	2484503	5,884,890	4,030,056	300,000	-906,875	6,186,250	13,877,662	10,214,946	3,662,716	-5,716,444	-2,523,534	0.797	2919184.529
1999	11,519,022	2609348	5,943,739	4,130,808	300,000	-906,875	5,279,375	14,228,370	10,374,547	3,853,824	-1,862,621	-1,425,551	0.712	2743922.509
2000	11,634,212	2735442	6,003,176	4,234,078	300,000	-906,875	4,372,500	14,469,654	10,537,254	3,932,400	2,069,779	-440,100	0.636	2501006.318
2001	11,750,554	2862796	6,063,208	4,339,930	600,000	-906,875	3,465,625	14,713,351	11,003,138	3,710,213	5,779,992	244,588	0.567	2103690.602
2002	12,338,082	2991424	6,366,369	4,448,428	300,000	-906,875	2,558,750	15,429,506	11,114,797	4,314,710	10,094,702	1,755,960	0.507	2187557.832
2003	12,461,463	3166210	6,430,032	4,559,639	300,000	-906,875	1,651,875	15,727,673	11,289,671	4,438,002	14,532,703	2,786,127	0.452	2005976.8
2004	12,586,077	3297872	6,494,333	4,673,630	300,000	-906,875	745,000	15,983,949	11,467,962	4,515,987	19,048,691	3,770,987	0.404	1824458.831
2005	12,711,938	3430851	6,559,276	4,790,470	300,000	-906,875	-161,875	16,242,789	11,649,746	4,593,043	23,641,733	4,754,918	0.361	1658088.391
2006	13,347,535	3565159	6,887,240	4,910,232	600,000	-906,875	-1,068,750	17,012,694	12,397,472	4,615,222	28,256,956	5,683,972	0.322	1486101.643
2007	13,481,010	3700811	6,956,112	5,032,988	300,000	-906,875	-1,975,625	17,281,821	12,289,100	4,992,721	33,249,677	6,968,346	0.287	1432910.995
2008	13,615,821	3837819	7,025,673	5,158,813	300,000	-906,875	-2,882,500	17,553,640	12,484,486	5,069,154	38,318,831	7,951,654	0.257	1302772.483
2009	13,751,979	3976197	7,095,930	5,287,783	300,000	-906,875	-3,789,375	17,828,176	12,683,713	5,144,463	43,463,294	8,933,838	0.229	1178082.021
2010	13,889,499	4115959	7,166,889	5,419,978	300,000	-906,875	-4,696,250	18,105,458	12,886,867	5,218,591	48,681,884	9,914,841	0.205	1069811.126
2011	14,583,973	4257119	7,525,234	5,555,477	600,000	-906,875	-5,603,125	18,941,092	13,680,711	5,260,381	53,942,266	10,863,506	0.183	962649.8105
2012	14,729,813	4399690	7,600,486	5,694,364	300,000	-906,875	-6,510,000	19,229,503	13,594,850	5,634,653	59,576,919	12,144,653	0.163	918448.4614
2013	14,877,111	4543687	7,676,491	5,836,723	300,000	-906,875	-7,416,875	19,520,798	13,813,214	5,707,584	65,284,503	13,124,459	0.146	833307.2946
2014	15,620,967	4689124	7,753,256	5,982,641	300,000	-906,875	-8,323,750	20,410,091	14,035,897	6,374,194	71,658,697	14,697,944	0.13	828645.1758
2015	15,777,177	4836015	7,830,788	6,132,207	300,000	-906,875	-9,230,625	20,713,191	14,262,996	6,450,196	78,108,893	15,680,821	0.116	748222.7337
2016	15,934,948	4984375	7,909,096	6,285,512	600,000	-906,875	-10,137,500	21,019,323	14,794,609	6,224,715	84,333,608	16,362,215	0.104	647370.3426
2017	16,731,696	5134219	8,304,551	6,442,650	300,000	-906,875	-11,044,375	21,965,915	15,047,201	6,918,713	91,252,321	17,963,088	0.104	719546.1915
Total	294,562,393		145,303,393	106,878,169				375,082,344		91,252,321	742,337,222			

The annual maintenance for conventional boiler is included in the MFO purchase cost (column 3) and the annual license of RM 9000 is included into the cogeneration cost. The Internal Rate of Return (IRR) is 31% and the net present value of the project at the end of its 20-year lifetime is RM19.69 million. This indicates that the project is viable and would indeed bring savings to the company. The Figure 2-3 in the next page indicates the expected payback period of the project. It can be clearly seen that the payback period is approximately 4.5 year. The 4.5 year payback (industries prefer payback periods less than 4 years) is normally acceptable among the industries. A debt to equity ratio of 2 is used to obtain the debt flow and equity cash flow. The project is expected to service the loan for 20 years. The equity cash flow (as shown in Figure 2.4) and debt flow indicates that the project will be able to pay for itself with equity returned at around 5.5 years. The more influential factor is the high IRR value and the Net Present Value. The project is viable based on this two factors.

The results can be considered conservative but a risk analysis on three most probable variables, namely natural gas and electrical prices were made to give an indication of the variations in Internal Rate of Return, Net present Value and Payback Period. It should be noted that natural gas cost is approximately 70% of the total operating cost of a cogeneration plant and hence, Table 2-14 below provides a quick estimation of the payback period and IRR with gas prices varying from a low RM 9.50 to a high RM 12.00 per MMBtu.

Table 2-14 Risk Analysis on Natural Gas Price Variations (Case Study One)

NATURAL GAS PRICES/VARIABLE (RM/MMBTU)	PAYBACK	IRR
9.50	4.2	32
10.00	4.4	31
10.50	4.7	28
11.00	5	27
11.5	5.2	25
12.00	5.4	23

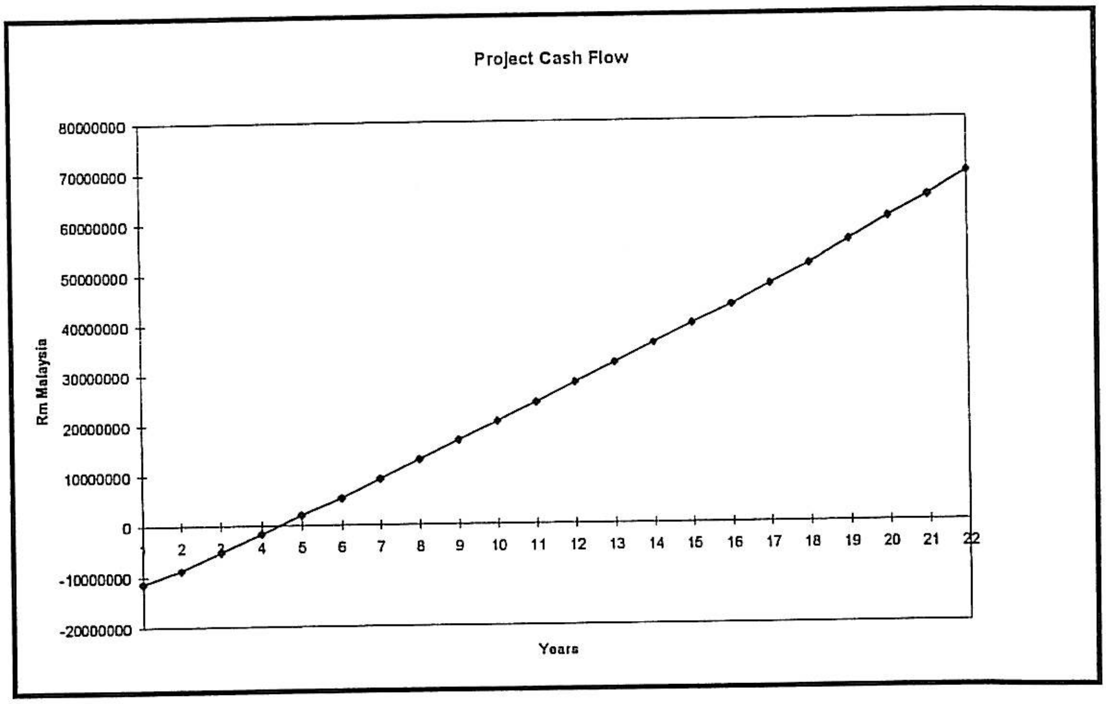

Figure 2-3 Expected Payback Period for Case Study One

The viability of the project, both economically and technically has been evaluated and found feasible. The next step is to discuss the terms and conditions with the relevant authorities and vendors before a final decision can be made regarding the status of the project.

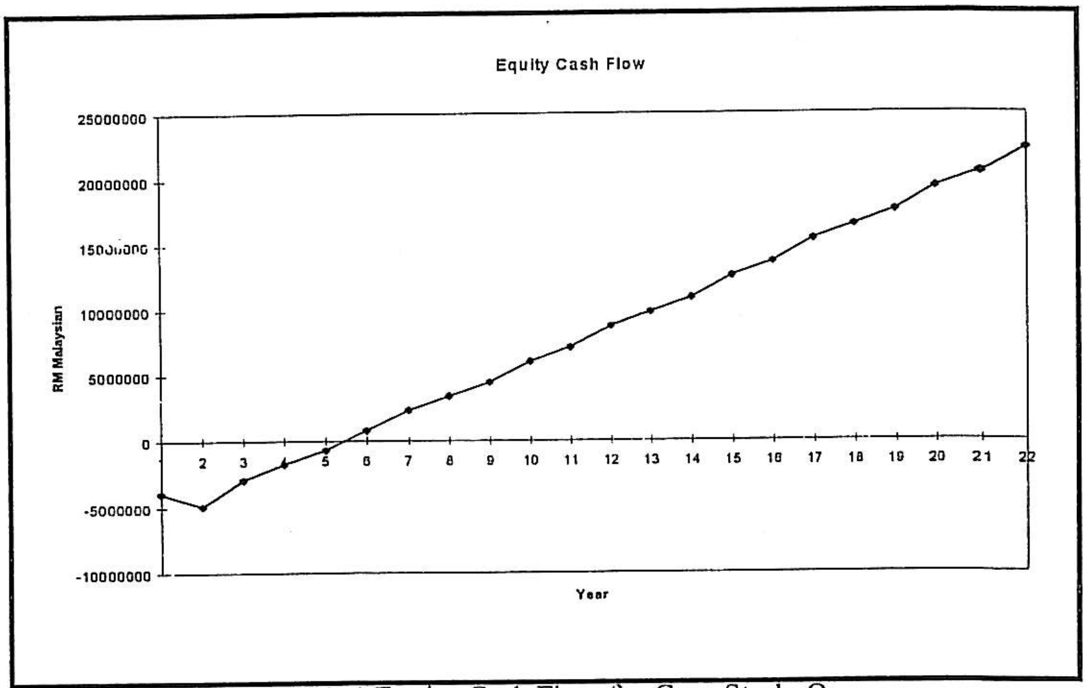

Figure 2-4 Equity Cash Flow for Case Study One

2.8 Conclusion for Case Study One

The proposed cogeneration plant is to supplement the power requirements of the plant 1 while fully supplying the expected steam load capacity for all the plants. The viability of the cogeneration plant is proven through the various analysis conducted where the economic viability is positive and thermoeconomics have indicated that energy is efficiently utilised by cogenerating while comparing with existing systems.

The proposed cogeneration is capable of producing additional steam by supplementary firing, thereby it will be able to meet additional steam demand if there is a need to do so.

The basic characteristics of the proposed cogeneration plant are listed in Table 2-15 below.

Table 2-15 Proposed Cogeneration Plant Characteristics

Turbine Type	Single Shaft Industrial Turbine with 5MW ISO rating
Turbine Power Output, kW	4100 kW- 30 ^{0}C ambient temperature, Full Load
Voltage Generation, kV	11,000
Frequency, Hz	50 Hz
Grid System	Parallel Operations or Island
Steam Generation Output, kg/hr	10,000kg/hr 150psig saturated, no supplementary firing
Fuel Type	Natural Gas , 31496 to 39370 kJ/Nm^3
Fuel Consumption, MMBtu/hr	50.88 - Full Load, no supplementary firing
Fuel Supply	Gas Pipeline
Standby Fuel Type	Light Fuel Oil
Estimated Required Area	18m X 10m
Control Systems	Governor Control/Micro-Processor
Emission Control Systems	Available for NOx (optional)
Auxiliary System	Fuel pump, water pump, starter motor etc.
Operating Hours, hr/year	8400 (scheduled Maintenance - twice a year and at 30,000 hours
Maintenance Cost, RM/kWh	0.01
Standby Power	4.1 MW
Top - Up Power	6.9 MW
Cost of Generation , RM/kWh	0.11

Figure 2-5 in the next page is the proposed plant layout.

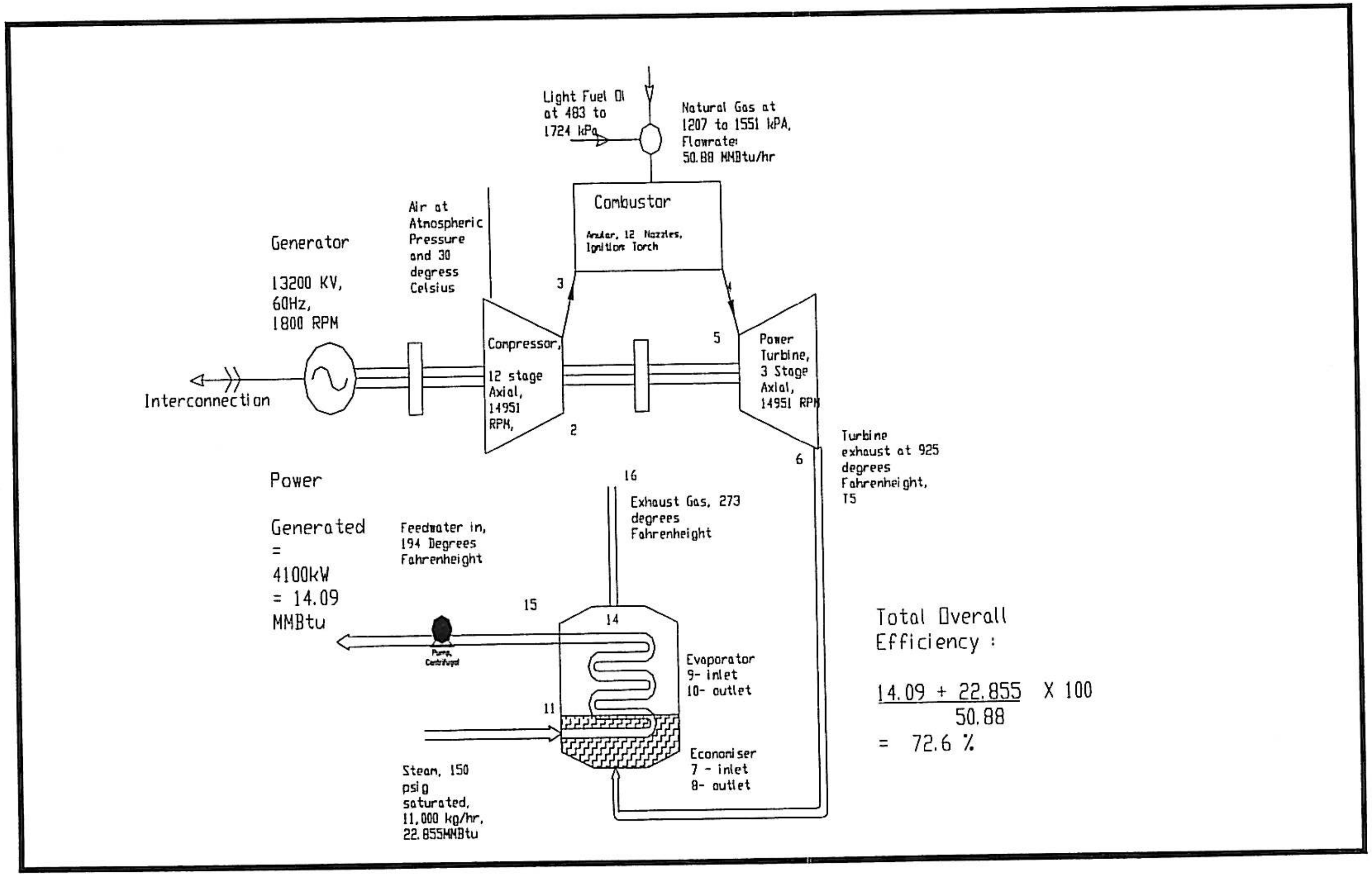

Figure 2-5 Basic Cogeneration Plant Layout for Case Study One.

2.9 Findings of Case Study Two

Case Study Two can be divided into three plants, Plant 1, 2 and 3. Plant 1 has four boilers (one is on standby service) which supplies all its steam load and also to the other two plants. Plant 2 has an operating boiler that supplies the Plant 2 only with supplement steam from Plant 1.

The simple layout diagram of the plant is shown below:-

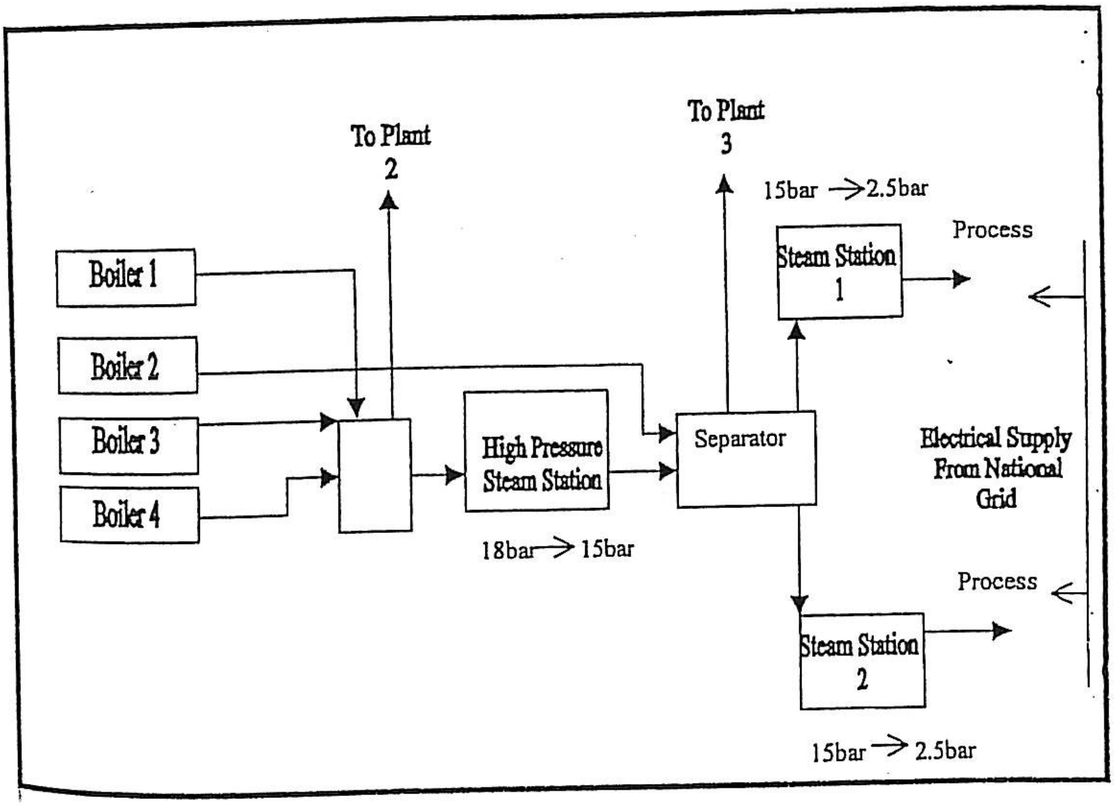

Figure 2.6 Simple Plant Layout of Case Study Two.

Plant 1 requires an average of 15,000 kg/hr of saturated steam at 18 bar. Peak demand for steam during 1997 (as of September 1997) is averaged at 25,000 kg/hr with the highest peak at approximately 34,000 kg/hr. The average and peak consumption for 1996 was 23,000 kg/hr and 28,000 kg/hr respectively. Maximum demand for electricity is averaged at 4650 kW.

The steam and electrical load of the plant is difficult to predict since it depends on the demand for the manufactured products.

The proposed cogeneration plant is 4100 kW (on site rated) gas turbine with a supplementary fired HRSG. (The HRSG provides approximately 10,000 kg/hr of steam without supplementary firing). Because the overall plant's production is dependent on a constant supply of steam, an existing boiler rated at 13,600 kg/hr was retained as a back up and standby boiler. The boiler will continuously supply 5000 kg/hr of steam, thus eliminating the need for continuos supplementary firing and providing immediate standby during unexpected shutdowns. Steam load of Plant 2 is provided by the Plant 2 boiler, therefore it will not be dismantled and thus eliminate the need for additional piping for the cogeneration system. The cogeneration plant will operate with supplementary firing when there is a peak demand only.

The study on the economics took into consideration the fuel required to operate the conventional boilers and the fuel saved by displacing the Plant 1 boilers. Electrical power produced by the cogeneration plant is sufficient for the energy demand of the plant during peak and off peak periods which eliminate the calculated Demand Factor. Hence the electrical purchase cost is limited to the standby and top-up charges for most months of the year. The present Boiler Room has sufficient area to accommodate the proposed cogeneration system.

This section will summarise the findings for Case Study Two. The table below provides details on the efficiency of the system:

Table 2-16 Thermodynamic Performance of Proposed Cogeneration Plant for Case Study Two

System/ Criteria	Reference Plant	Independent System	Dependent System (Supplementary firing and top-up power)
η**th, %**	30	27.6	20.87
EUF,%	56	69.48	86.14
FSR	N/A	0.32	0.94
η_{A}**, %**	N/A	73.23	N/A
IHR	N/A	2.22	1.00
$\eta_{HRSG/B}$**, %**	77	80	87.53
(η_0)%	21	69.48	73.96
F^T	5.62	3.61	4.53
F^T **–fired**	-	-	7.67

From the table above it can be seen that the efficiency values are lower compared to Case Study One. This is due to the higher-pressure steam and supplementary firing. Supplemental firing increases the heat to electrical ratio two fold and even though the fuel consumption increases but the electrical output remains the same. The HRSG efficiency is higher for the dependent plant since supplementary firing increases the steam capacity. Table 2-17 shows the cash flow analysis for a 20-year period. The expected payback period is shown in Figure 2-7.

Table 2-17 Cash Flow Analysis for 20-Year Period for Case Study Two

	1	2	3	4	5	6	7	8	9	10	11
Year	*Present Cost*		*With Cogeneration*						*Costing (cash flow)*		
	Electrical Cost Without Cogen	MFO (for Boilers)	Electrical Cost with Cogen (savings)	MFO Savings	Natural Gas (for Gas turbine)	Standby Charges	Cogen Maintenance	Annual License	Cost (No Cogen)	Cost (Cogen)	Project Cash Flow
1996	5,332,092	4,221,884	-		-	-	-	-	9,753,976	(12,000,000)	(12,000,000)
1997	6,054,695	4,269,413	5,017,725	2,803,975	3,469,202	392,083	300,000	9,000	10,524,108	6,672,693	3,851,415
1998	6,737,224	4,312,107	5,067,902	2,780,609	3,503,894	261,755	300,000	9,000	11,249,331	7,275,469	3,973,862
1999	8,675,860	4,355,228	5,017,223	2,808,415	3,538,933	264,372	300,000	9,000	13,231,089	9,317,756	3,913,332
2000	8,762,619	4,398,780	4,967,051	2,836,499	3,574,322	267,016	300,000	9,000	13,361,399	9,508,188	3,853,211
2001	9,200,750	3,271,304	5,165,733	2,978,324	3,610,065	269,686	600,000	9,000	12,672,054	8,816,749	3,855,305
2002	9,292,758	3,304,017	5,114,075	3,271,304	3,646,166	272,383	300,000	9,000	12,796,775	8,438,944	4,357,830
2003	9,385,685	3,337,057	5,062,935	3,304,017	3,682,628	275,107	300,000	9,000	12,922,742	8,622,525	4,300,217
2004	9,479,542	3,370,428	5,012,305	3,337,057	3,719,454	277,858	300,000	9,000	13,049,970	8,806,919	4,243,051
2005	9,953,519	3,538,949	5,212,798	3,503,910	3,756,649	280,637	300,000	9,000	13,692,468	9,122,046	4,570,423
2006	10,053,054	3,574,339	5,160,670	3,538,949	3,794,215	283,443	300,000	9,000	13,827,393	9,314,432	4,512,961
2007	10,153,585	3,610,082	5,109,063	3,574,339	3,832,157	286,277	600,000	9,000	13,963,667	9,807,700	4,155,967
2008	10,255,121	3,646,183	5,057,972	3,610,082	3,870,479	289,140	300,000	9,000	14,101,304	9,701,868	4,399,435
2009	10,357,672	3,682,645	5,007,393	3,646,183	3,909,184	292,032	300,000	9,000	14,240,317	9,896,956	4,343,360
2010	10,875,555	3,866,777	5,207,688	3,828,492	3,948,275	294,952	300,000	9,000	14,942,333	10,258,379	4,683,953
2011	10,984,311	3,905,445	5,155,611	3,866,777	3,987,758	297,901	300,000	9,000	15,089,756	10,462,027	4,627,729
2012	11,094,154	3,944,499	5,104,055	3,905,445	4,027,636	300,880	300,000	9,000	15,238,653	10,666,669	4,571,984
2013	11,205,096	3,983,944	5,053,015	3,944,499	4,067,912	303,889	600,000	9,000	15,389,040	11,172,327	4,216,713
2014	11,317,147	4,023,784	5,002,485	3,983,944	4,108,591	306,928	300,000	9,000	15,540,930	11,079,021	4,461,909
2015	11,883,004	4,224,973	5,202,584	5,975,916	4,149,677	309,997	300,000	9,000	16,307,977	9,698,151	6,609,826
2016	12,001,834	4,267,223	5,150,558	6,035,676	4,191,174	313,097	300,000	9,000	16,469,057	9,896,094	6,572,962
2017	12,121,852	4,309,895	5,099,053	6,096,032	4,233,086	316,228	300,000	9,000	16,631,747	10,094,976	6,536,771
Total	140,221,950	60,664,639	81,440,199		59,871,017		5,400,000	135,000		146,689,324	68,214,035

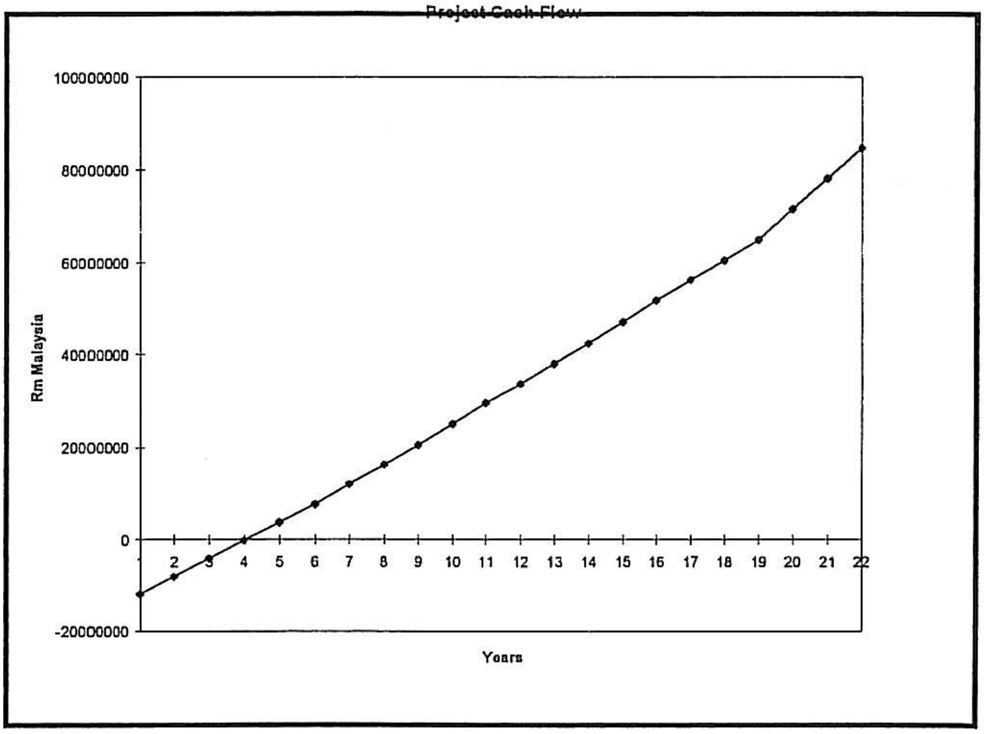

Figure 2-7 Expected Payback Period for Case Study Two

Table 2-18 Risk Analysis on Natural Gas Prices Variations (Case Study Two)

NATURAL GAS PRICE/VARIABLE (RM/MMBTU)	PAYBACK	IRR (%)
9.50	3.9	35
10.50	4.1	33
10.50	4.5	32
11.00	4.7	30
11.50	4.9	29
12.00	5.1	28
15.00	9.5	12

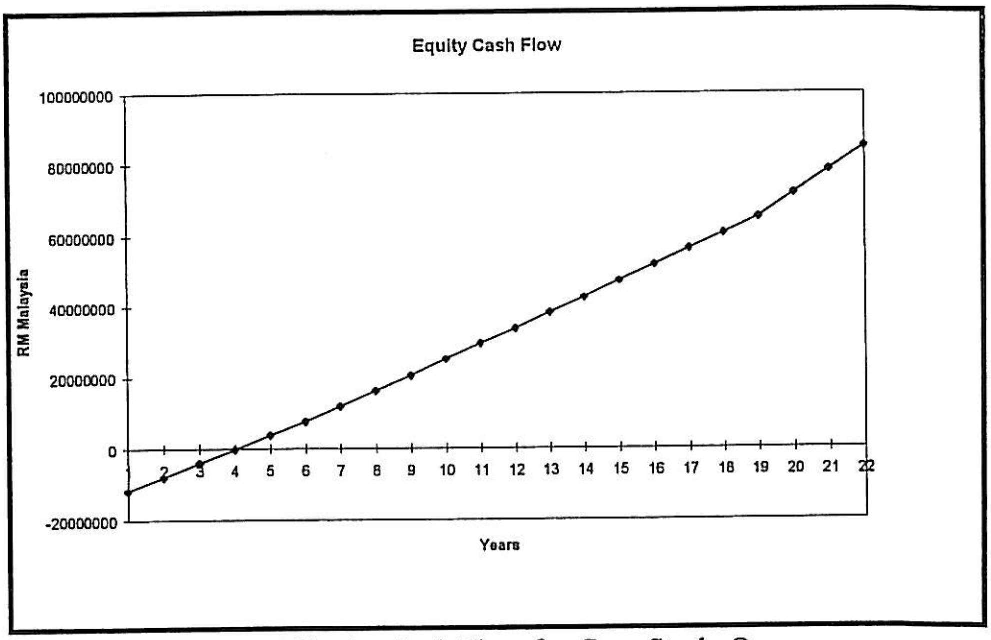

Figure 2-8 Equity Cash Flow for Case Study One

2.10 Conclusion for Case Study Two

It can be seen that the plant has a higher efficiency than the conventional system. This means that the technical aspect is a positive scenario. The expected payback yields a positive figure of 4.1 years. The payback is similar to Case Study One since the proposed cogeneration plant will be able to supply most of the electrical requirements of the plant. The IRR is less than Case Study One since the operating cost includes medium fuel oil cost for the back-up boilers and Plant 2 boilers.

A gas turbine cogeneration plant is feasible technically and economically for this plant. The risk analysis below for various natural gas prices indicates that the project will have a payback of less than 5 years.

The plant's cost of generating power is RM 0.124, which is slightly higher than the RM 0.11 for Case Study One. This is due to the fact that the cogenerating plant displaces not all medium fuel oil. This undisplaced fuel cost is included into the cost of cogenerating since the **combined cost** method is employed in this analysis.

2.11 Overall Conclusion

Both case studies have proven to be economically and technically feasible. The cost of generating power on site is lower when compared to purchase power cost from the utility. The thermodynamic efficiency is higher than the conventional system, which translates into conservation of fossil fuel energy. The risk or sensitivity analysis using natural gas price variations have indicated that the projects will still continue to have acceptable payback.

These observations are important, since it displaces the notion that cogeneration is not feasible in the Malaysian environment. Other factors, such as regulations, theoretical, surety in fuel prices etc may be contributing to the lack of interest in this field in Malaysia. The findings of this study are given in the next chapter.

CHAPTER III

CONCLUSION

3.1 Introduction

The research work that was conducted over a period of 18 months was successful in terms of the meeting the objectives while maintaining the scope of the study as listed in Chapter One

3.2 Results of Research

The research was able to assess the potential of cogeneration in selected Malaysian Industries. The research found that cogeneration is not only technically feasible but economically viable as well. Malaysian industries will be able to benefit from a cogeneration plant if the design is implemented properly. It should be emphasised that, the feasibility may vary from industry to industry, hence the need for a thorough evaluation. The research work provided insights to the mechanism that is required to make cogeneration operate successfully in the Malaysian environment. The methodology used in conducting the economic and technical feasibility can be employed for most industries. The methodology employed can be considered as conservative and hence more rigorous and competitive figures may yield better results.

3.3 Case Studies

Cogeneration was found to be feasible in the two selected industries. The findings for both the case studies are listed below:-

a) The simple payback for Case Study One is calculated to be 4.5 years with equity cash flow of 5.5 years for a debt to equity ratio of 2. Case Study

Two has a simple payback of 4 years with equity cash flow of 4 years for similar debt to equity ratio.

b) The per unit cost of generating electricity in RM/kWh proved to be lower than the present cost of purchase for both Case Studies where saving up to 29% was obtained when compared to existing utility purchase cost.

c) The cogeneration plant for both case studies also found that the fuel consumed by the cogeneration plat is utilised more efficiently than the conventional system.

d) The calculated efficiencies were found feasible as shown in Chapter 2. The overall efficiency of the independent system for Case Study One is higher when compared to Case Study Two due to the difference in the steam load. Supplementary firing in Case Study Two's dependent plant increased the overall efficiency, when compared to the independent plant since additional heat energy is obtained. The EUF for the dependent cogeneration plant in Case Study One is lower since a large portion of the total required electrical energy is purchased from the grid, unlike the dependent plant for Case Study Two, which requires lesser quantity of purchased power from the utility. (The calculated values can be compared between Table 2.9 and Table 2.10).

In short, analysis on both Case Studies indicate that cogeneration has the potential to be feasible both, technically and economically in Malaysia provided certain problems are addressed. Several factors were identified to be important for cogeneration to be feasible, namely:-

a) High energy utilisation

The electrical and heat demand must be of significant value with preferably a heat to electrical demand ratio of 2 to 2.5, to promote the use of cogeneration. A much higher heat to electrical ratio may not be feasible due to the fact that electrical power is more expensive compared to heat energy. At the same time too low a ratio will not be feasible since prime movers such as gas turbines, have lower efficiencies for small generation capacity. Therefore a balance must be achieved to ensure a good economic feasibility is achieved.

Case Study One, the heat to electrical ratio is approximately 1.6 for the present plant operations and by producing electricity (an expensive form energy)on site, the monthly billing charges will be reduced. If the ratio was much lower, excess heat energy will be generated, thereby reducing the efficiency of the system but still maintaining economic viability since electrical power purchase is lowered. Therefore a plant may be economically viable but a failure technically. This factor is critical in ensuring that the technical and economics of the system is justified at all times.

Case Study Two has a much higher ratio, which suited a gas turbine cogeneration system well. The problem with this case study was that the cogeneration system is unable to provide the full steam load of the plant, hence requiring a standby/ back-up boiler to be in operation at all times where the boiler in Plant 2 (of Case Study Two) operates without any changes. The standby/back-up boiler increased the availability of the plant even if there was a unscheduled shutdown of the gas turbine.

Since both case studies required high quality steam, gas engines were not taken into consideration. Gas engines can be considered when the heat load is more towards hot water applications or low quality steam.

b) Close proximity with existing natural gas pipelines

This factor is important in natural gas fired cogeneration plants. The use of light fuel oil as a substitute is not advisable since the prime movers performance will be affected. The maintenance of the prime mover is more frequent if the substitute fuel is used. Cogeneration is the efficient use of energy and the use of natural gas promotes a cleaner environment, hence the use of liquid fossil fuel will defeat the purpose of cogeneration.

Both Case Studies have gas pipelines within the vicinity of their industrial estates, thus making availability of fuel more accessible.

c) The need for high availability

Operations of both case studies are frequently disrupted by constant power failure. Gas turbine cogeneration plants have reliability close to 98%. This means that the failure rate of the turbine is only 2% of the total operating time, which means that for a plant such as Case Study One, the unscheduled shutdown is approximately 168 hours or 7 days. Conforming to the maintenance schedule increases this availability. Power disruption from the utility cannot be described in hours due to the fact that power failure affects the process flow, which translates into losses.

3.4 Problems Facing Cogeneration in Malaysia

There are several factors affecting the development of cogeneration in Malaysia. These factors were identified after much discussion with the parties concerned in cogeneration namely Gas Malaysia Sdn. Bhd., Tenaga Nasional, potential cogenerators and vendors.

The problem is due to one important factor, which is that the interest of all parties must be protected when implementing the cogeneration system. Jabatan Bekalan Elektrik dan Gas, (JBEG) as the regulatory body has no interest other than ensuring all parties are treated fairly. It's responsibility is to ensure that the regulations for cogenerators be finalised and approved by the government but this has been delayed by certain circumstances.

The factors affecting cogeneration in Malaysia are listed below:

1) Insufficient knowledge on the system and its advantage of cogeneration plants in industries. Malaysian industries lack maturity where no initiative is taken to improve their efficiency since production is considered the most critical aspect.

Technological development is not given a priority since the production and profits are still maintained. The lack of high technical skills is also one of the problems faced since maintenance of high precision equipment such as gas turbines require skilled personnel. This lack translates into increased maintenance cost due to import of highly skilled labour. Europeans and other developed nations have implemented strict regulations on efficiency to ensure that industries consume energy on par with the production output. Introducing stringent laws and regulations on energy efficiency can accelerate improvements in the aspects mentioned above.

2) Natural gas prices have yet to be revised for cogeneration purposes. Current price tariff is based on the Fuel Oil Index in Singapore which natural gas is priced approximately 30% higher which is not attractive. At current a medium size user (5000cfm to 50,000cfm per month) pay an approximately price of RM 10.50 to 11.50 per MMBtu while MFO is approximately RM 8.23 per MMBtu. The vast difference of cost is not balanced by the energy content since MFO has a gross calorific value of approximately 39MJ/l and natural gas at current production statistics is at 38.73MJ/l.

3) Interconnecting regulations have not been finalised by the Tenaga Nasional. This is an important factor to ensure the operation of a cogeneration plant does not effect the national grid and vice versa. Strict regulations would reduce the possibility of damage to either party.

4) Actual status of future cogenerator is still vague. Cogenerators have no assurance on fuel prices, regulations on cogenerating since this have yet to be officially confirmed. This problems are critical since fuel cost of cogeneration plant is easily 70% of the total operational cost and changes in regulation might make a feasible plant become otherwise.

5) High capital cost. The cost of gas turbines can be averaged RM 2.5million per megawatt. (MW). The larger turbines are less costly when compared to the smaller turbines and since most cogenerators fall into the latter and this as mentioned earlier is the high capital cost being incurred by implementing gas turbine fired cogeneration plant

3.5 Suggestions on Improving the Potential of Cogenerating in Malaysia

The economics and technical viability have both been positive for the case studies. This means that cogeneration should be pursued in a more concerted effort to enable Malaysian industries to reap the benefits by implementing it.

The suggestions below can create a potential environment for cogenerating. These suggestions are:

1) **Regulate natural gas prices.**

The price of natural gas needs to be finalised and approved by the relevant authorities. A fixed cost with future price predictions is important to ensure the economic analysis is valid. The current pricing method, which depends on the Singapore Fuel Index should be revised. This is due to the high base value which will cause the natural gas price to increase at a higher rate than medium fuel oil prices, which have a lower base value. By reducing the base value a more competitively priced value can be obtained. This will provide cogenerators a benchmark and avoid unnecessary conflicts when prices escalate.

2) **All interconnection details must be standardised to avoid irregular systems.**

By regulating the system, Tenaga Nasional Berhad (TNB) and the cogenerators will be able to operate more efficiently. Faults can be detected easily and hence remedied without much loss. JBEG, as the regulatory body must ensure TNB and the cogenerator comply to the standards.

3) **Regulations must be approved and printed in black and white.**

This is to give assurance to cogenerators on their status. At present, regulations are still pending and hence changes made may affect the cogenerator. An important issue that must be addressed is the standby power, which is supplied by TNB. Enforcement must be there to ensure cogenerators are not denied the standby power without valid reasons. If there is case where the cogenerator was denied the standby power, TNB must be able to prove that it was unable to do so. This particular point should be included within the regulation 9.0 “Duties of The Electric Utility”.

4) **Reducing High Capital Cost**

The high capital cost can be lowered by encouraging local companies to participate in the construction of the plant. Gas turbine technology may not be within the reach of local companies but HRSG design, piping, civil works and control systems can be developed indigenously or co-operatively with the foreign technology. For example, at present the boiler design is a foreign concern in Malaysia, where their respective foreign partners design all boilers and construction is done locally. The cost can be reduced if the boiler was designed and built locally. The reason for the foreign partnership is that local companies are not confident enough to give process guarantees[1] to their clients. Local industries must develop this aspect become competitive in the world markets.

3.6 Overall Conclusion

The research was able to establish specific points on cogeneration in Malaysian industries. This points can be considered as the most important issues or factors that is important to cogeneration :

a) Cogeneration is a economic and technically feasible system in Malaysian industries if the gas prices, regulations etc are properly implemented.

b) Regulations must be approved and fully legalised to increase the confidence of the industries.

c) Natural gas prices must be pegged to a transparent factor and increments should be justified and be competitively priced against medium fuel oil.

d) The benefits of cogeneration are not only in economics but also the overall efficient energy utilisation of the nation in whole. Cogeneration also provides the opportunity for high technology transfer. Other hidden benefits are the lower emissions and hence cleaner environment.

It can be concluded that the research has reached its objective while maintaining the scope of study.

[1] "Process Guarantee" is where the designer assures the client that the design will comply with his or her requirements, where if failing to do so will penalise the designer.